Chapter 2

Total Petroleum Systems of the Michigan Basin—Petroleum Geology and Geochemistry and Assessment of Undiscovered Resources

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By Christopher S. Swezey, Joseph R. Hatch, Joseph A. East, Daniel O. Hayba, and John E. Repetski

Chapter 2 of 4

Geologic Assessment of Undiscovered Oil and Gas Resources of the U.S. Portion of the Michigan Basin

By U.S. Geological Survey Michigan Basin Province Assessment Team

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Conversion Factors

Inch/Pound to SI

Multiply	By	To obtain
	Length	
inch (in.)	2.54	centimeter (cm)
inch (in.)	25.4	millimeter (mm)
foot (ft)	0.3048	meter (m)
mile (mi)	1.609	kilometer (km)
	Volume	
barrel (bbl), (petroleum, 1 barrel=42 gal)	0.1590	cubic meter (m^3)

Initialisms

TPS	total petroleum system
AU	assessment unit
MMBO	million barrels of oil
BBO	billion barrels of oil
MMCFG	million cubic feet of gas
BCFG	billion cubic feet of gas
TCFG	trillion cubic feet of gas
BNGL	barrels of natural gas liquids
MMBNGL	million barrels of natural gas liquids
USGS	U.S. Geological Survey
CAI	color alteration index

Total Petroleum Systems of the Michigan Basin—Petroleum Geology and Geochemistry and Assessment of Undiscovered Resources

By Christopher S. Swezey, Joseph R. Hatch, Joseph A. East, Daniel O. Hayba, and John E. Repetski

Introduction

In 2004, the U.S. Geological Survey (USGS) conducted an assessment of the undiscovered, technically recoverable oil and natural gas resources in the U.S. portion of the Michigan Basin. The primary goal of the USGS National Oil and Gas Assessment project is to develop geologically based hypotheses regarding the potential for additions to oil and gas reserves in priority areas of the United States. The focus of the project is to determine the distribution, quantity, and availability of oil and natural gas resources with an emphasis on quantifying undiscovered oil and natural gas resources that may underlie Federal lands. The approach in the Michigan Basin, as in all assessed provinces, was to establish the framework geology, define the total petroleum systems (TPS), define assessment units (AU) within each total petroleum system, and assess the potential for undiscovered, technically recoverable petroleum resources in each assessment unit.

This chapter describes the geologic setting of the Michigan Basin, the petroleum exploration and production history in the basin, and the petroleum assessment terminology and methodology that were used for this assessment. This information is followed by descriptions and assessment results for the 6 total petroleum systems and 13 assessment units in the basin, along with supporting geological data, maps, and geochemical data that were used in the assessment.

Geologic Setting

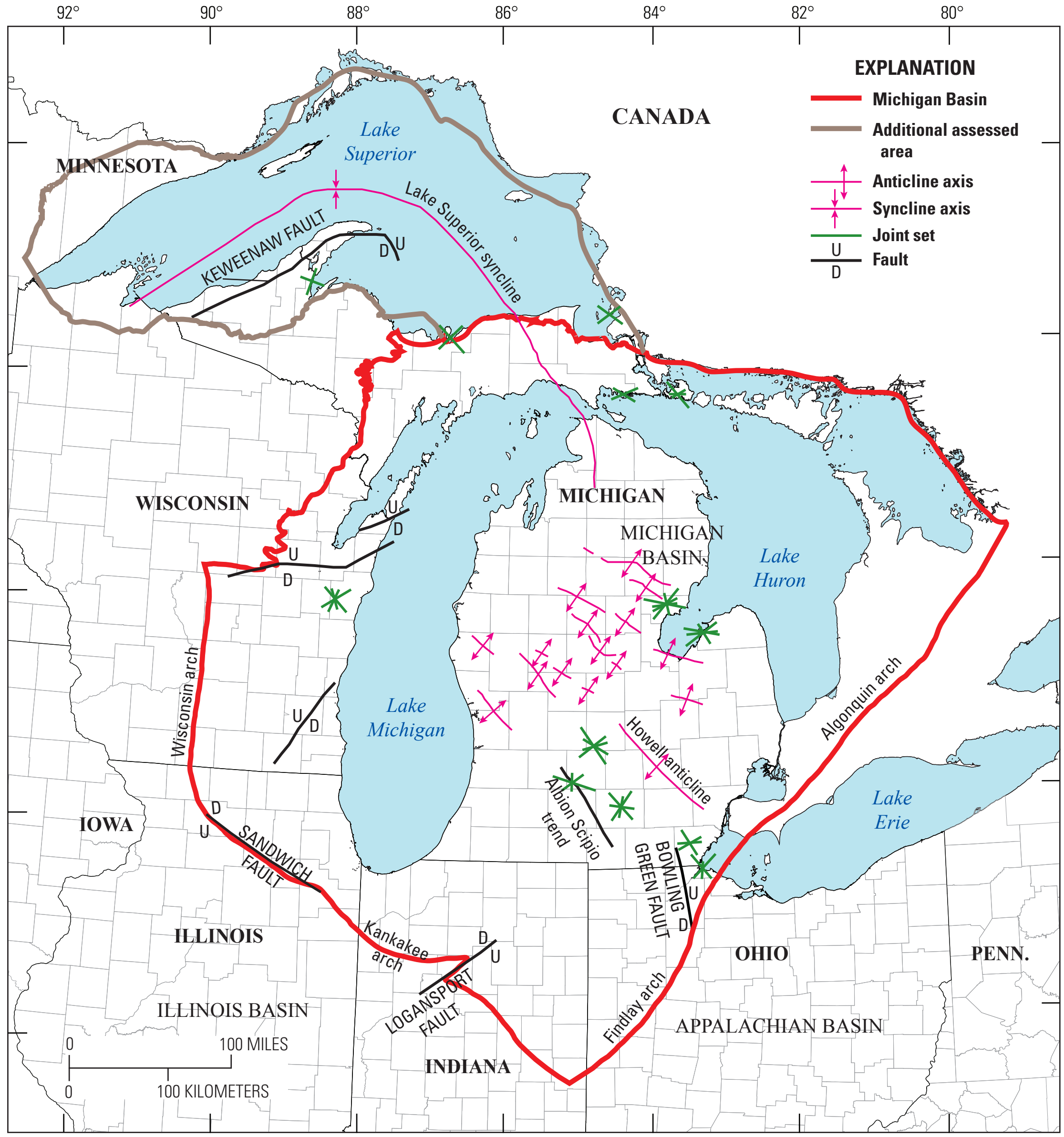
The Michigan Basin has a polygonal, roughly circular shape and is centered on the State of Michigan, United States, although portions of the basin extend into adjacent States and into Canada (fig. 1). The basin is bounded on the southeast by the Findlay arch and the Algonquin arch (which separate the Michigan Basin from the Appalachian Basin) and bounded on the southwest by the Kankakee arch and the Sandwich fault (which separate the Michigan Basin from the Illinois Basin). On the west, the Michigan Basin is bounded by the Wisconsin arch and Precambrian strata in Wisconsin. The northern boundary of the Michigan Basin is traditionally located along the contact between Precambrian and Cambrian strata in the northern peninsula of Michigan. For this project, however, the assessed area extends north and west beyond the traditional boundary of the basin into the Lake Superior region to encompass potential Precambrian petroleum source rocks and reservoir rocks in the northern peninsula of Michigan.

The Michigan Basin is underlain by igneous, metavolcanic, and metasedimentary “basement” rocks (fig. 2). These pre-sedimentary basement rocks are capped by an unconformity, above which lie younger sedimentary strata that are more than 16,000 feet (ft) thick in the central part of the basin (figs. 3 and 4). Most of the sedimentary strata are Paleozoic age, ranging from Cambrian through Pennsylvanian (fig. 5). The documentable Pennsylvanian age strata, however, are capped by discontinuous lenses (up to 400 ft thick) of either unfossiliferous Pennsylvanian red sandstone, siliciclastic mudstone (shale), and gypsum (Kelly, 1936; Benison and others, 2011) or strata of the Middle Jurassic Ionia Formation (Cross, 1998, 2001; Dickinson and others, 2010a,b) (fig. 6). The Paleozoic strata and (or) Pennsylvanian or Jurassic strata are overlain by Quaternary sediments that are primarily of glacial origin.

Few studies have been published on structural features in the Michigan Basin. Some faults have been identified in the southern portion of the basin (fig. 1), and many of the oil and gas fields near the basin center trend northwest along anticlines (see fig. 7). These anticlines are interpreted as shear folds associated with Appalachian tectonic events (Prouty, 1988; Versical, 1990), and many of these anticlines are associated with faults and flower structures at depth (Hatch and others, 2005).

Petroleum Exploration and Production History

The Michigan Basin has a long history of petroleum exploration and production (Cohee and Landes, 1958; Vary and others, 1968; Westbrook, 2005). The geographic distribution of oil and gas fields in the U.S. portion of the Michigan Basin in 2004 is shown in figure 7 (http://energy.cr.usgs.gov/oilgas/noga) and Keith and Wickstrom, 1992). Early settlers discovered oil seeps in southeastern Michigan, in southwestern Ontario, Canada, and on the eastern part of Manitoulin Island



The base map for this figure is from Nicholson and others (2004).

Figure 1. Map showing structural features of the Michigan Basin (modified from maps by Cohee and Landes, 1958; Prouty, 1988). Additional joint orientation data are from Holst and Foote (1981). D, downthrown side of fault; U, upthrown side of fault.

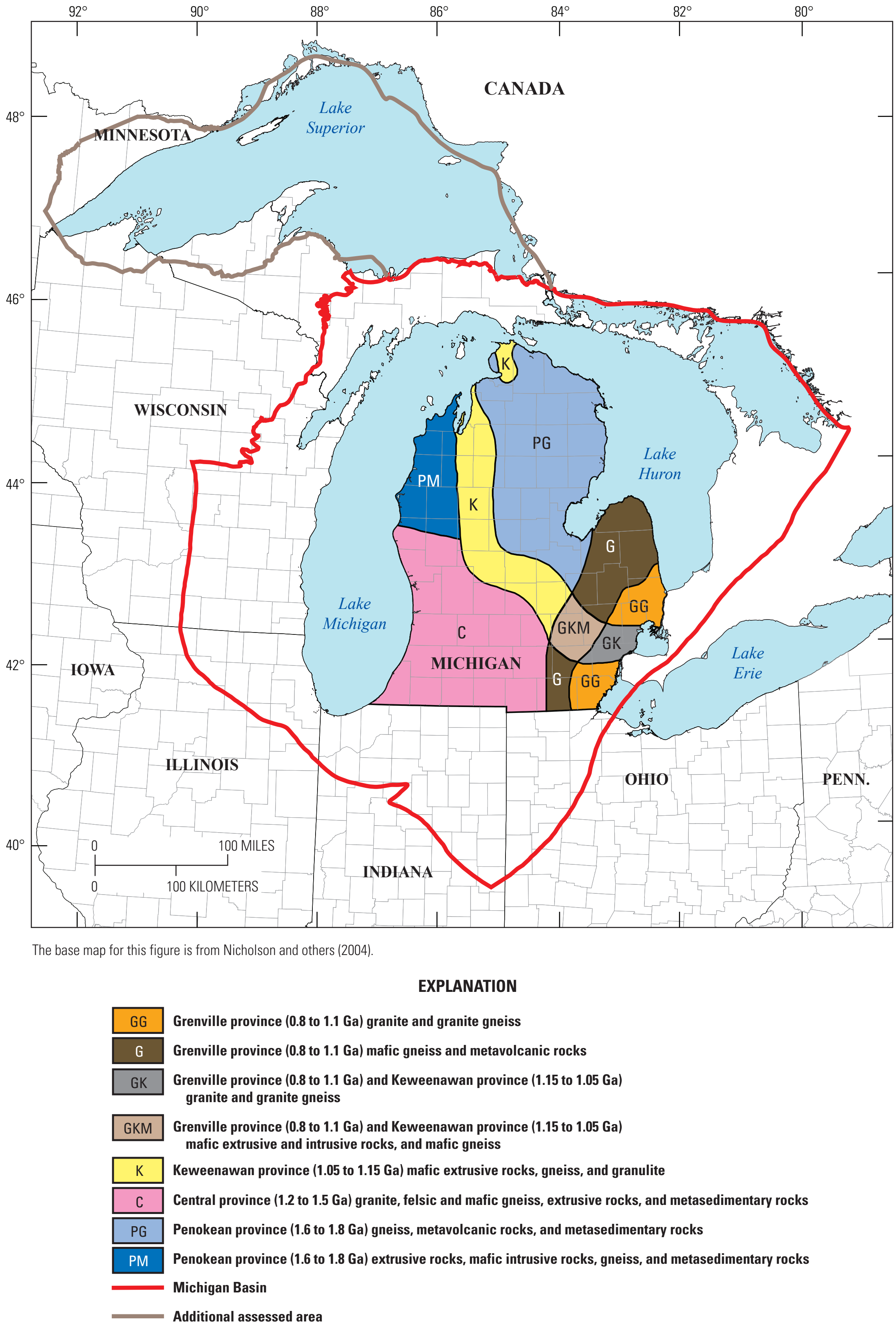


Figure 2. Map showing basement provinces in the central part of the Michigan Basin (modified from Hinze and others, 1978). Ga, Giga-annum (billion years). (See explanation on page 4.)

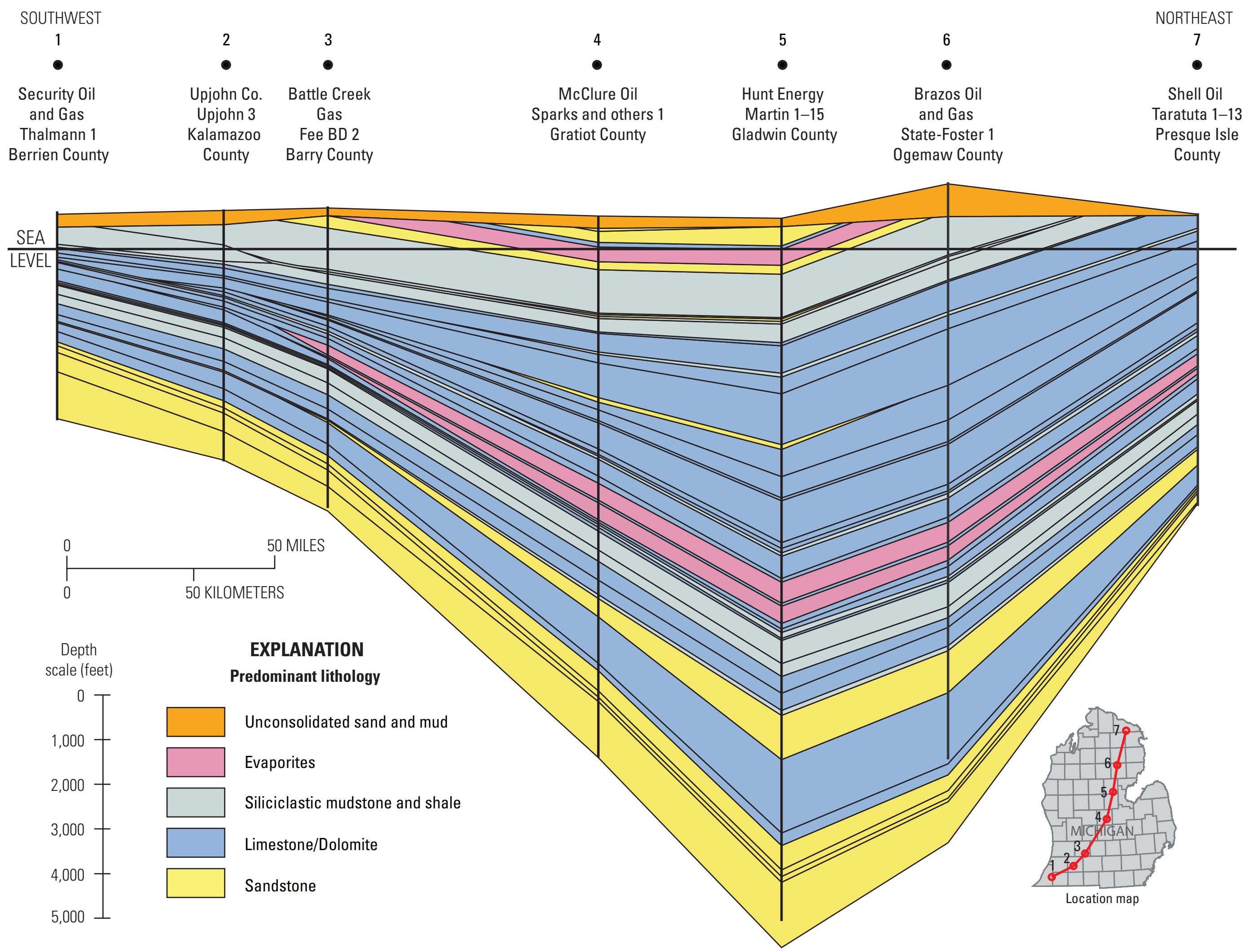
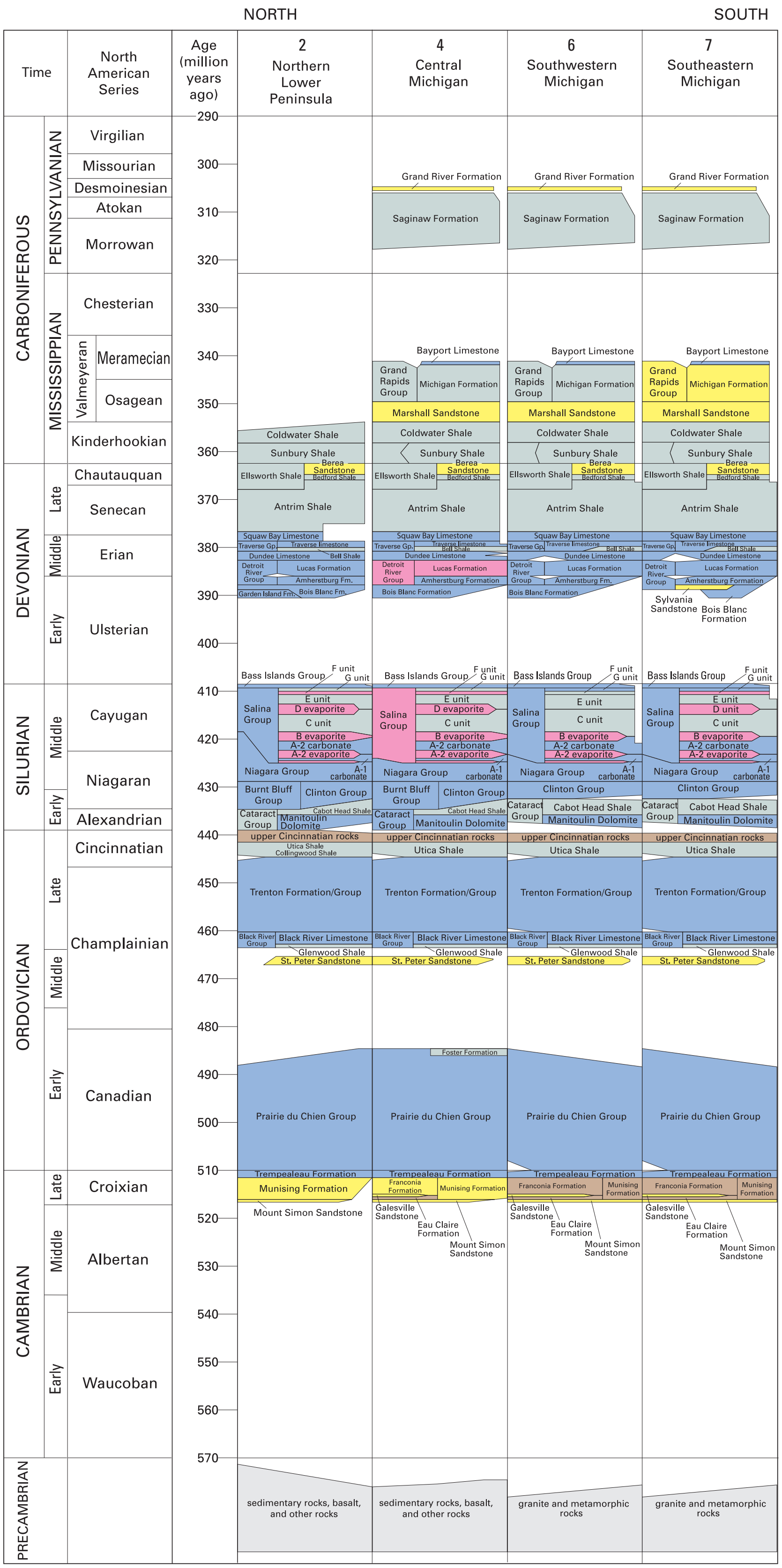
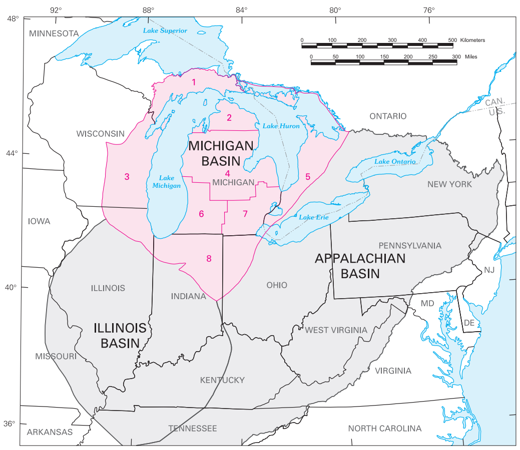


Figure 3. Southwest-northeast geologic cross section through the central part of the Michigan Basin (modified from Fisher and Barratt, 1988).

The base map for this figure is from Nicholson and others (2004).

Figure 4. Structure map on top of Precambrian basement in the central part of the Michigan Basin (from Catacosinos and Daniels, 1991).





Extent of the Michigan Basin, shown in red, and of the Appalachian and Illinois Basins, shown in gray. Swezey (2008) subdivides the Michigan Basin into the eight regions shown on the above inset map. The generalized stratigraphy of four of these regions are shown in the stratigraphic columns to the left. The numbers at the top of the stratigraphic columns (2, 4, 6, and 7) correspond to region numbers on the inset map. Inset map is modified from American Association of Petroleum Geologists (AAPG) (1984) and Swezey and others (2005).

EXPLANATION OF LITHOLOGY

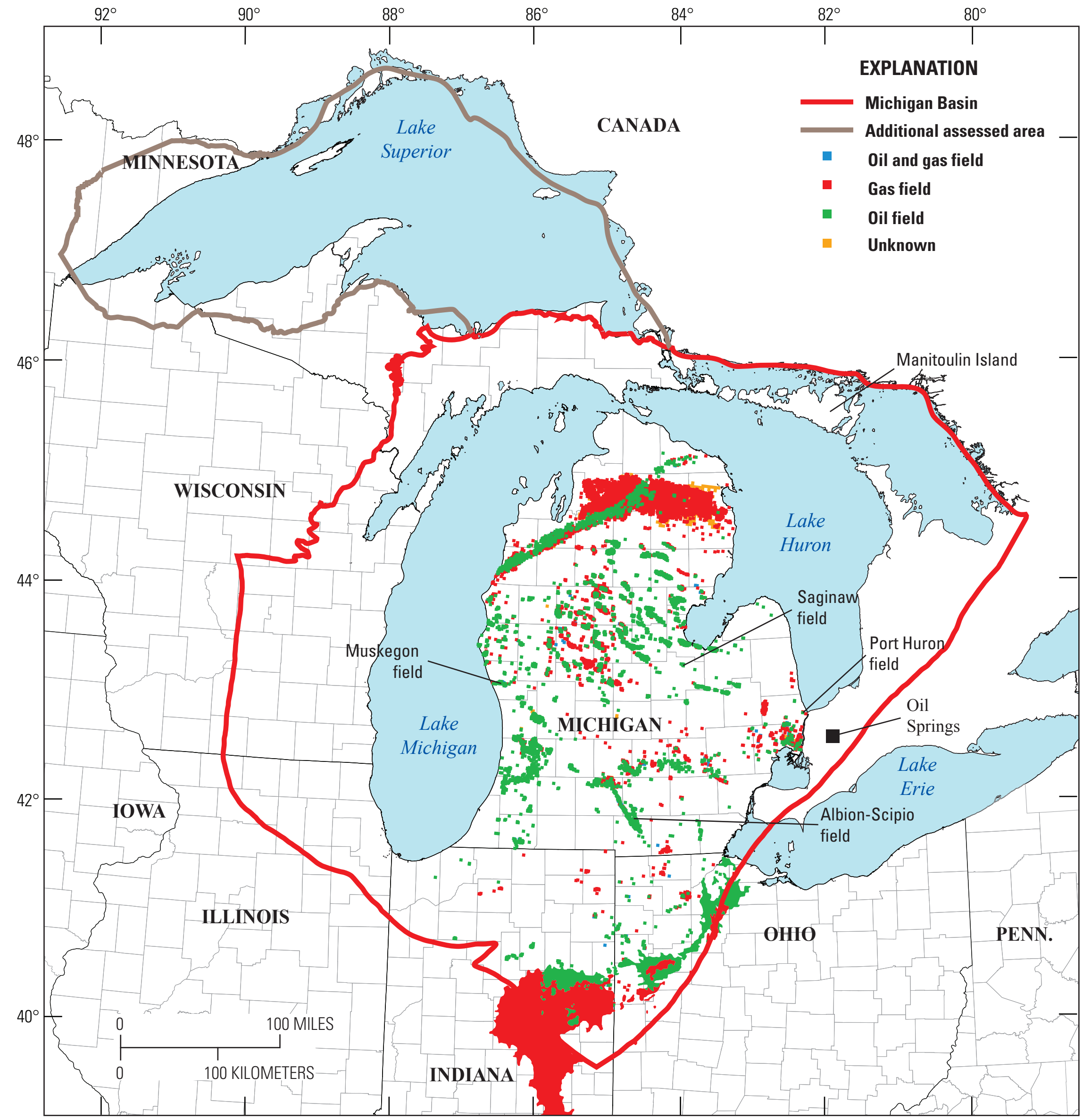
Although not designated as a separate lithology, some coal beds are present in Pennsylvanian strata in the Michigan Basin.

- Evaporite
- Carbonate rock or chert
- Sandstone
- Interbedded sandstone and mudstone
- Mudstone
- Section not present

Figure 5. Generalized Paleozoic stratigraphy of the Michigan Basin. Modified from Sweezey (2008). Stratigraphic columns (2, 4, 6, and 7) and nomenclature shown are from the American Association of Petroleum Geologists (1984). Fm., Formation; Gp., Group. (Click here to open full-size, high resolution image.)

The base map for this figure is from Nicholson and others (2004).

Figure 6. Map showing the extent of the Jurassic strata (Ionia Formation) in the central part of the Michigan Basin (shaded area; modified from Dorr and Eschman, 1970). These strata consist of red siliciclastic sediments and gypsum and may actually be of Pennsylvanian age (Kelly, 1936; Benison and others, 2011).



The base map for this figure is from Nicholson and others (2004).

Figure 7. Map showing the oil and gas fields in the U.S. portion of the Michigan Basin; data are from U.S. Geological Survey Web site (http://energy.cr.usgs.gov/oilgas/noga) and from Keith and Wickstrom (1992). Identified locations are discussed in the text

in Canada (fig. 7). Early settlers also discovered gas seeps in Wayne and St. Clair Counties in southeastern Michigan. The first oil field that was discovered in the basin was the Oil Springs field, which is located at the town of Oil Springs in Ontario, Canada (fig. 7). Beginning in 1851, oil was mined at the town of Oil Springs from the Devonian Dundee Limestone and overlying gravel. Initially, this oil was used as a paving product. In 1858, James Williams dug a well to a depth of 14 ft at Oil Springs. This well filled with oil, from which kerosene was distilled and used as a fuel for illumination. Other oil wells were soon dug in the vicinity. In 1859, the first commercial oil well was completed by Edwin Drake in Devonian sandstone at Titusville, Pennsylvania, United States, and this drilling technology was subsequently transferred to Ontario. By late 1861, more than 400 oil wells were active at Oil Springs, and 32 of these wells were developed using Drake's drilling technology. In 1866, oil was discovered at Petrolia, about 9 miles (mi) north of Oil Springs.

After the discoveries of oil at Oil Springs and Petrolia, exploration extended west into Michigan (Cohee and Landes, 1958; Vary and others, 1968; Westbrook, 2005). In 1886, the Port Huron field (fig. 7) was discovered in St. Clair County, Michigan, and this field produced small quantities of oil from the Devonian Dundee Limestone at depths of 550 to 575 ft. The first commercial oil field, however, was established in 1925 with the discovery of the Saginaw field (fig. 7) in Saginaw County, Michigan. This field produced oil from the Devonian Berea Sandstone at a depth of approximately 1,825 ft. In 1927, the Muskegon field (fig. 7) was discovered in Muskegon County, Michigan. This field produced oil from the Middle Devonian Traverse limestone (informal subsurface term) as well as oil and gas from the Middle Devonian Dundee Limestone (informal subsurface term). This field also produced gas from a thin bed called the "Upper Monroe" near the top of the Middle Devonian Detroit River Group. Some gas from this field was sold for distribution in the city of Muskegon.

Oil and gas fields within the Michigan Basin are primarily located in Michigan (fig. 7). A brief review of the exploration history of the basin shows several peaks in oil and gas production that are associated with production from new stratigraphic intervals often facilitated by advances in technology (fig. 8). For example, one peak production period occurred during the 1930s. Most of this production was from new fields that were located in Middle Devonian strata along northwest-trending anticlines in the central part of the basin. A second production peak occurred around 1960; most of this new production was from fields in Middle Ordovician carbonate strata (for example, the Albion-Scipio field; fig. 7). A third production peak occurred around 1980 and was associated with the widespread use of 2-D seismic data to identify pinnacle reef reservoirs in the Middle Silurian Niagara Group. Finally, a peak in gas production occurred during the late 1990s that is associated with new production from the Upper Devonian Antrim Shale in the northern part of Michigan. The production peaks in both oil and gas production in Michigan are reflected in figures 9 and 10, which illustrate cumulative oil and gas production, respectively, from 1925 through 2003 for various productive stratigraphic intervals (from Wylie and Wood, 2005).

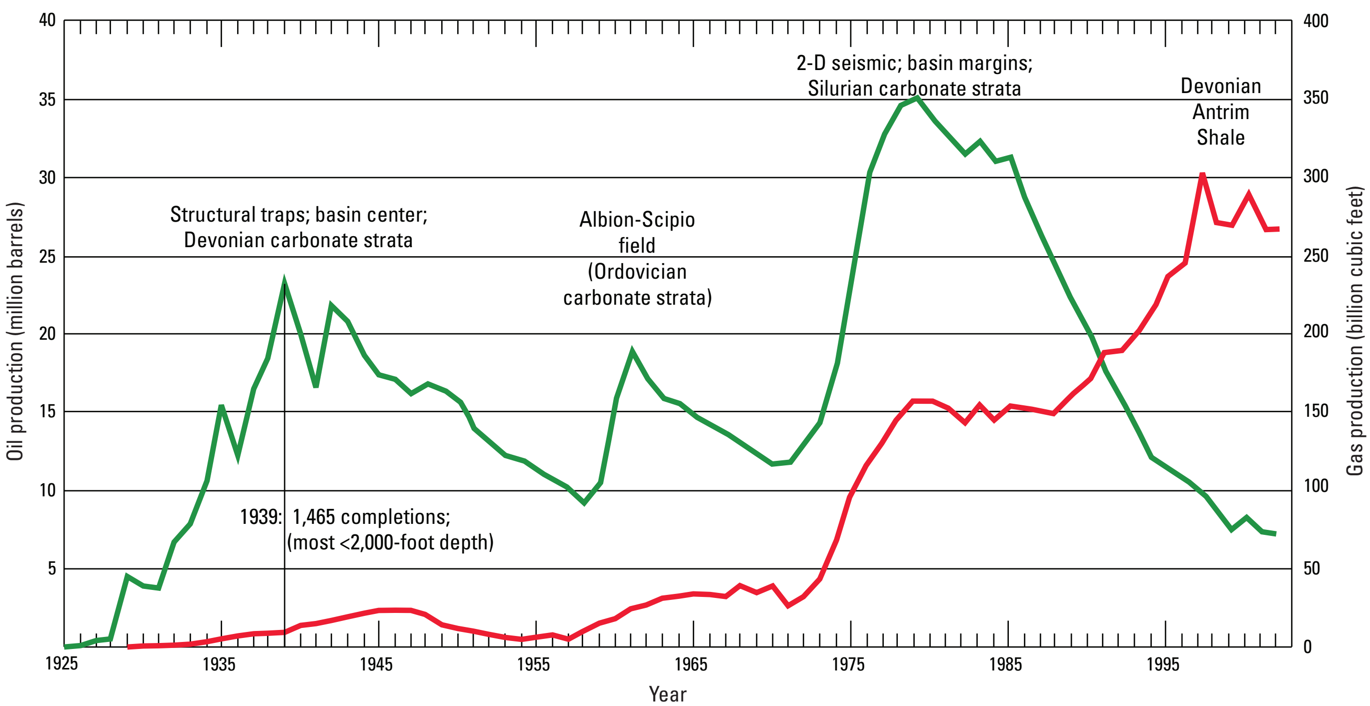


Figure 8. Chart of the annual oil and gas production in Michigan (modified from Duszynski, 2004). Green line denotes oil production in million barrels of oil. Red line denotes gas production in billion cubic feet of gas. Peaks in production are identified.

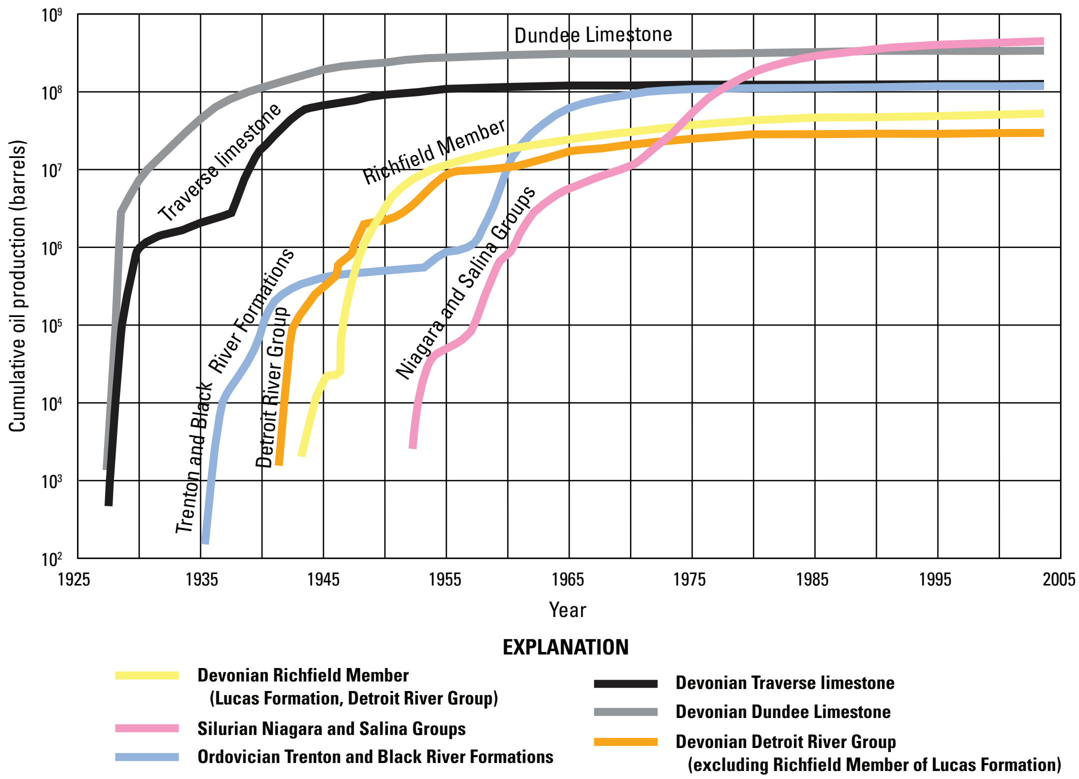


Figure 9. Chart of cumulative oil production from 1925 through 2003 for various stratigraphic intervals in Michigan (from Wylie and Wood, 2005).

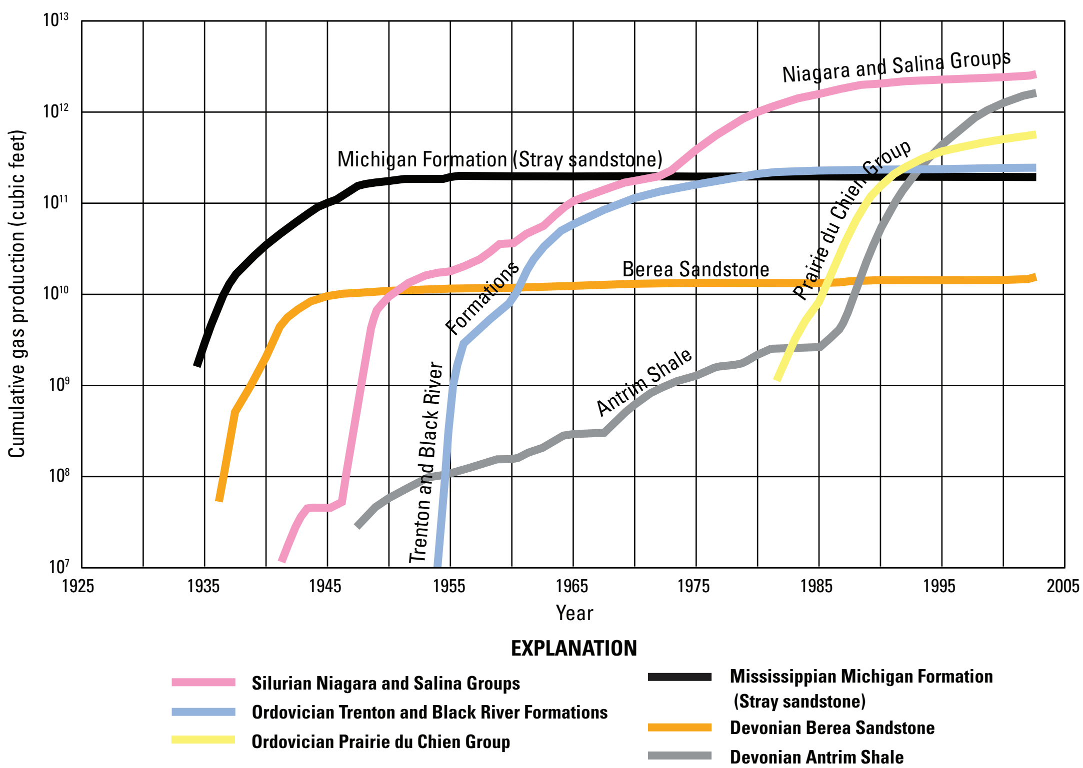


Figure 10. Chart of cumulative gas production from 1925 through 2003 for various stratigraphic intervals in Michigan (from Wylie and Wood, 2005).

Petroleum Assessment Terminology and Methodology

In this publication, the term “hydrocarbons” is used to denote molecules composed of hydrogen and carbon, whereas the term “petroleum” is used to denote mixtures of liquid or gaseous hydrocarbons that may also include helium and hydrocarbon compounds containing sulfur, nitrogen, oxygen, and metals. The assessment of undiscovered petroleum resources is possible because petroleum is distributed in groups of accumulations that share common geological attributes (Houghton and others, 1993). An accumulation of petroleum is often called a field, which is defined as “...an individual producing unit consisting of a single pool or multiple pools of petroleum related to each other based on a single structural or stratigraphic feature” (Gautier and others, 1995, p. 11). Furthermore, the chemical compositions of petroleum in a given field can often be correlated with the chemical compositions of organic matter in specific stratigraphic intervals indicating the source of the petroleum.

The definition/description of a petroleum system includes (1) a source rock for the petroleum, (2) the physical and chemical characteristics of the petroleum derived from that source rock, and (3) all of the geologic elements and processes that are essential for a petroleum accumulation to exist (Magoon and Dow, 1994). The geologic elements and processes of the petroleum systems include (1) source-rock physical characteristics and chemical and mineralogical compositions, (2) source-rock organic-matter thermal maturation, (3) petroleum compositions and migration pathways, and (4) characterizations of the reservoir rocks, traps and seals.

Petroleum systems may be classified as known systems, hypothetical systems, or speculative systems (Magoon and Dow, 1994). For known systems, geochemical studies show correlation between hydrocarbons contained within the petroleum source rock and a petroleum accumulation. Hypothetical systems have a source rock identified by geochemical information but no known geochemical correlation between the petroleum source rock and a petroleum accumulation. Speculative systems do not have a source rock identified by geochemical information, but the existence of either a petroleum source rock or a petroleum accumulation is postulated on the basis of other evidence.

For a given petroleum system, the volume of rock to be assessed is divided into various reservoir intervals that share common attributes. These reservoir intervals are called “assessment units” that are typically defined according to stratigraphic and structural parameters. These parameters should be sufficiently homogenous such that one methodology of resource assessment is applicable to a given assessment unit. In the case of the Michigan Basin, most assessment units are defined according to stratigraphy and lithology. Some petroleum systems in the Michigan Basin contain only one assessment unit (reservoir interval), whereas other petroleum systems contain numerous assessment units (reservoir intervals).

Assessment units are classified as either conventional or continuous (unconventional) depending upon the nature of petroleum accumulation within the assessment unit (Gautier and others, 1995; U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995; Schmoker, 2005; Schmoker and Klett, 2005). Conventional assessment units contain discrete petroleum accumulations of a range of sizes, with well-defined fluid contacts (water, oil, gas) within the reservoir. In contrast, continuous (unconventional) assessment units are petroleum accumulations that have poorly defined boundaries within the reservoir, exist more or less independently of the water column, and are pervasive over a large geographic area. Different assessment methodologies are applied to conventional assessment units and continuous (unconventional) assessment units.

Conventional assessment units may be classified as established, frontier, or hypothetical. Established assessment units are defined as having more than 13 petroleum accumulations that are larger than the minimum size established for the assessment. Frontier assessment units are defined as having 1 to 13 petroleum accumulations that are larger than the minimum size established for the assessment. Hypothetical assessment units are defined as having no accumulations of petroleum larger than the minimum size established for the assessment.

Perception of the size and distribution of petroleum accumulations in an area can be distorted by several artifacts of the petroleum discovery process. One artifact of this process is an emphasis on the discovery of large fields (Kontorovich and others, 2001). Larger petroleum fields are easier to discover, hence, larger fields tend to be discovered earlier in the exploration history, and the number of discoveries per well tends to decline as more wells are drilled (Drew and Schuenemeyer, 1993; Kaufman, 1993; Root and Mast, 1993; LaPointe, 1995). Thus, the discoverability of a petroleum field is a function of the petroleum field size. Petroleum field discoverability is also a function of the number of wells drilled in the basin. Specifically, the discoverability of a petroleum field is greater if fewer wells have been drilled in the basin (Meisner and Demirmen, 1981). Thus, the probability of an exploration success tends to decrease as more wells are drilled, and progressively more drilling is required to find a petroleum accumulation of a given size (Kaufman, 1993). Furthermore, as more wells are drilled, fewer fields and smaller fields are discovered causing the mode of the distribution of the magnitudes of discovered fields to decrease (Schuenemeyer and Drew, 1983; Root and Attanasi, 1993). As a result, the true average size of the underlying field population is less than the average size that is calculated early in the exploration history. Most estimates of the ultimate recoverable resources of an oil or gas field, however, eventually increase with time as more wells are drilled (Drew and Schuenemeyer, 1993). This phenomenon is referred to as “field growth,” and it is an artifact of the petroleum discovery process (Attanasi and Root, 1994). To account for field growth, the USGS applies a “growth factor” to reported field sizes in order to account for resources expected to be added to reserves as a consequence of the extension of known fields, the revision of reserve estimates, and the addition of new pools to discovered fields (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995; Attanasi and others, 1999). Thus, in the USGS assessment terminology, “grown” fields are fields where the volume of oil or gas resources is the amount of estimated ultimate recoverable resources.

“Economic truncation” is another artifact of the petroleum discovery process that distorts perception of the underlying parent population of petroleum fields (Schuenemeyer and Drew, 1983). The term “economic truncation” refers to the fact that smaller oil and gas fields may be unreported because they are not profitable to produce. Thus, the USGS uses a minimum field size (for grown field sizes) when working with oil and gas statistics. For the 2004 assessment of the Michigan Basin, the USGS used a minimum grown field size of 0.5 million barrels of oil (MMBO) for oil accumulations and a minimum grown field size of 3 billion cubic feet (BCFG) for gas accumulations. These minimum grown field-size values are the same minimum field-size values used in USGS assessments of most other basins in the United States.

Petroleum Systems of the Michigan Basin

The USGS has defined six total petroleum systems (TPS) and 13 assessment units in the Michigan Basin based on (1) petroleum source rocks (source-rock properties, organic matter thermal maturation, and timing of petroleum generation and migration) and (2) reservoir rocks (sequence stratigraphy and petrophysical properties) and hydrocarbon traps (trap formation and timing) (fig. 11). In stratigraphic order, from oldest to youngest, these total petroleum systems and assessment units are as follows:

1. Precambrian Nonesuch TPS
   Precambrian Nonesuch AU

2. Ordovician Foster TPS
   Ordovician Sandstones and Carbonates AU

3. Ordovician to Devonian Composite TPS (I, II, III)
   Ordovician Trenton/Black River AU (I)
   Ordovician Collingwood Shale Gas AU (I)
   Silurian Burnt Bluff AU (I)
   Middle Devonian Carbonates AU (II)
   Devonian Antrim Continuous Oil AU (III)
   Devonian to Mississippian Berea/Michigan Sandstone| AU (III)

4. Silurian Niagara/Salina TPS
   Silurian Niagara AU
   Silurian A-1 Carbonate AU
   Devonian Sylvania Sandstone AU

5. Devonian Antrim Shale TPS
   Devonian Antrim Continous Gas AU

6. Pennsylvanian Saginaw TPS
   Pennsylvanian Saginaw Coal Bed Gas AU

The Ordovician to Devonian Composite TPS is a composite petroleum system that is divided into three parts (I, II, III) based on the principal contributing petroleum source-rock interval(s). Possible source-rock intervals for this total petroleum system include Middle Ordovician Trenton Formation, Middle Ordovician Collingwood Shale, Middle Devonian Detroit River Group, and Upper Devonian Antrim Shale.

Precambrian Nonesuch Total Petroleum System

The Precambrian Nonesuch TPS (fig. 12) is part of an estimated 400- to 40,000-ft-thick sequence of Mesoproterozoic volcanic and siliciclastic strata that fill an aborted intracratonic rift system called the “midcontinent rift system,” which extends about 800 mi from Kansas into Lake Superior and then south beneath the Michigan Basin (Van Schmus and Hinze, 1985). The rift system began opening about 1,200 Ma (Mega-annum, million years), and it rests on and is surrounded by older igneous and metamorphic “basement” rocks (fig. 2). The Precambrian Nonesuch TPS contains one possible petroleum source rock, the Precambrian Nonesuch Shale, and one assessment unit, the Precambrian Nonesuch AU.

Structural and Stratigraphic Framework

Within the midcontinent rift system, the Lake Superior portion (also called the “Lake Superior syncline”) contains six basins (Seglund, 1989): (1) Ashland Basin, (2) Bayfield Basin, (3) Gogebic Basin, (4) Sibley Basin, (5) Jacobsville Basin, and (6) the Seney Basin (fig. 13). These six basins are fault-block basins that are separated from each other by transverse faults. Mesoproterozoic strata that fill the midcontinent rift system have been described from outcrops in the Lake Superior region and from core and seismic data in central Michigan.

The general stratigraphy (fig. 14) of the Mesoproterozoic midcontinent rift system in the Lake Superior region, in the vicinity of the Keweenaw Peninsula, is described by Halls (1966), Daniels (1986), Mudrey and Ostrom (1986), Ojakangas (1986, 1988), Daniels and Elmore (1988), Elmore and others (1988), Kalliokoski (1988), Catacosinos and Daniels (1991), and Mauk and Burruss (2002). According to these authors, the pre-sedimentary basement igneous and metamorphic strata are capped by an unconformity. Above the unconformity lies 300 ft of thick, fine-grained quartz sandstone named the Bessemer Quartzite at some locations and the Barron Quartzite at others. The Bessemer Quartzite and (or) Barron Quartzite are overlain by (and may interfinger with) a 9,000- to 15,000-ft-thick series of predominantly basaltic units (compositions range from rhyolite to olivine tholeiite) that are collectively called the Portage Lake Volcanics. The Portage

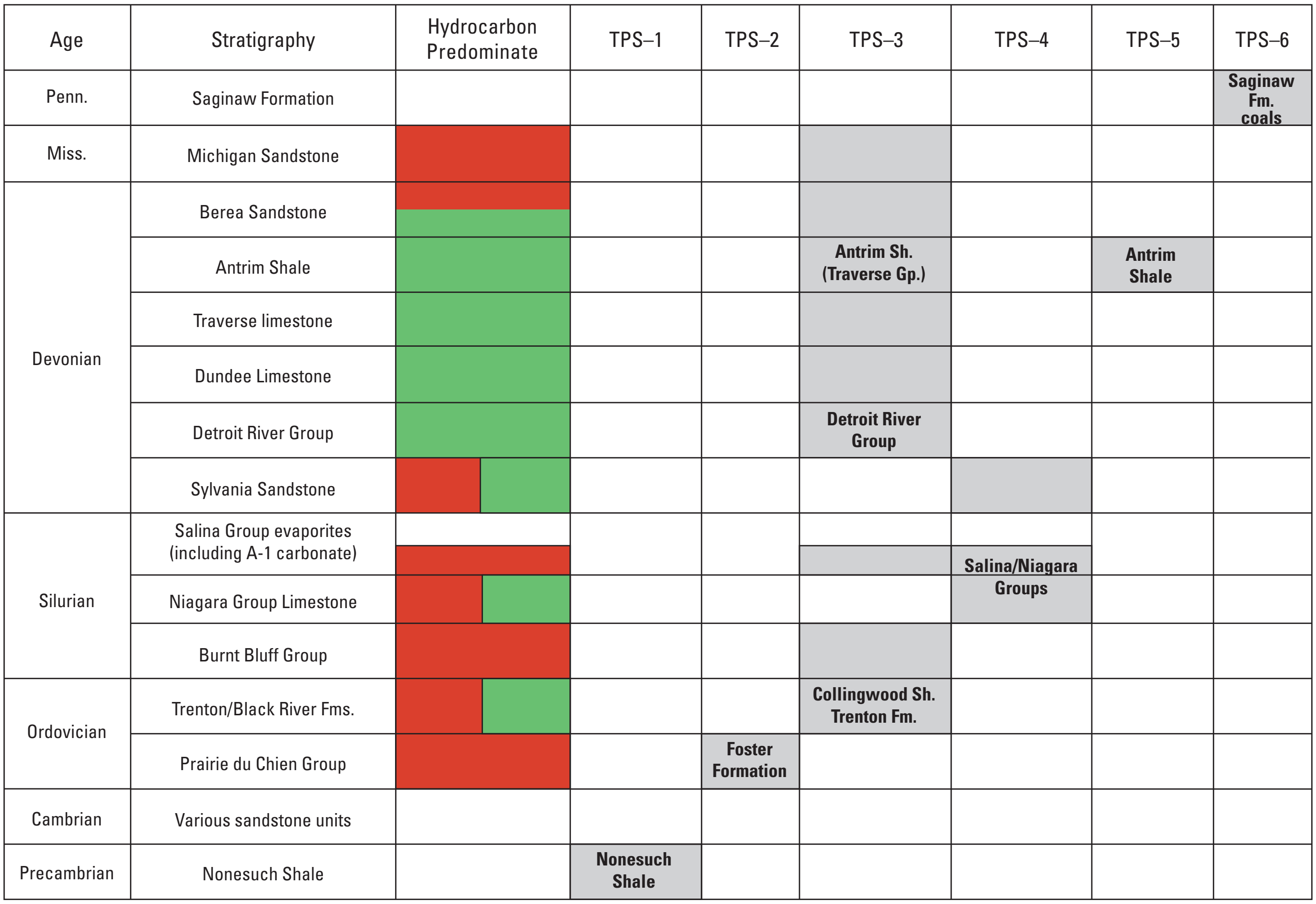


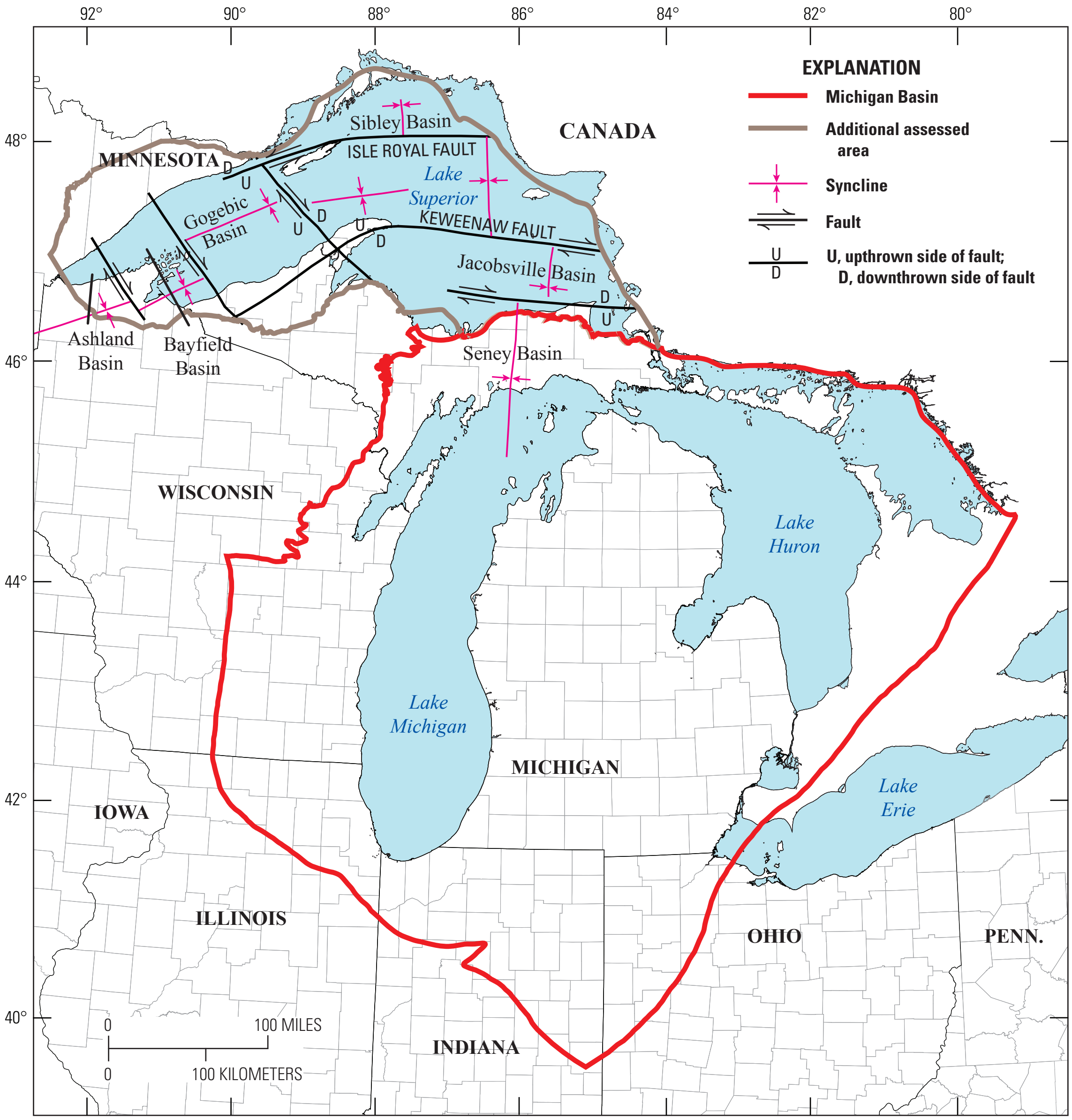
Figure 11. Stratigraphic distribution of predominate petroleum types (green, oil; red, gas) within the six total petroleum systems (TPS–1 through TPS–6) in the Michigan Basin. Identified petroleum source rocks (shown in bold letters) are listed under each TPS. Gray shading within the TPS column indicates the assessment units. Fm., Formation; Fms., Formations; Gp., Group; Miss., Mississippian; Penn., Pennsylvanian.

Lake Volcanics is conformably overlain by and interfingers with a 350- to 7,000-ft-thick unit of red-brown volcanogenic conglomerate, sandstone, stromatolitic limestone, and volcanic rock that are collectively called the Copper Harbor Conglomerate. In turn, the Copper Harbor Conglomerate is gradationally overlain by, and interfingers with a 125- to 800-ft-thick unit of petroliferous and metalliferous green to black siltstone, shale, and fine-grained sandstone, the Nonesuch Shale. It is gradationally overlain by and interfingers with an as much as 12,000 ft thick unit of red-brown lithic sandstone and siliciclastic mudstone (shale) that is named the Freda Sandstone. The Copper Harbor Conglomerate, Nonesuch Shale, and Freda Sandstone are assigned to the Oronto Group. The Freda Sandstone (uppermost formation of the Oronto Group) is capped by an unconformity, above which lies a >3,000-ft-thick unit of ferruginous feldspathic and quartz sandstone (with some siltstone, shale, and conglomerate) that is called the Jacobsville Sandstone. In some places, however, the unconformity beneath the Jacobsville Sandstone has been cut down into older strata, so that the Jacobsville Sandstone lies on an unconformity above the Portage Lake Volcanics, the Bessemer Quartzite, and (or) the igneous and metamorphic basement rocks. The Jacobsville Sandstone of the northern peninsula of Michigan is stratigraphically equivalent to the Bayfield Group of Wisconsin, which is a 4,360-ft-thick unit of sandstone that is divided into three formations, which are from base to top (1) Chequamegon Formation, (2) Devils Island Formation, and (3) Orienta Formation. According to some interpretations, the Devils Island Formation of the Bayfield Group in Wisconsin is stratigraphically equivalent to the Hinckley Sandstone in Minnesota and to the Upper Cambrian Galesville Sandstone and (or) the Mount Simon Sandstone in Michigan. Also, the Orienta Sandstone of the Bayfield Group in Wisconsin is correlative with the Fond du Lac Sandstone in Minnesota.

South and east of the Lake Superior region, the stratigraphy of the midcontinent rift system in the central part of the Michigan Basin is poorly understood. The igneous and metamorphic basement rocks (figs. 2 and 4) are cut by a major gravity anomaly (gravity high) that extends south from Lake Superior and then turns east and is eventually truncated at the

The base map for this figure is from Nicholson and others (2004).

Figure 12. Map showing an outline of the maximum possible extent of the Precambrian Nonesuch Shale and the limits of the midcontinent rift in the United States and Canada (shaded area).



This base map for this figure is from Nicholson and others (2004).

Figure 13. Map showing the structural features in the Lake Superior region (from Seglund, 1989).

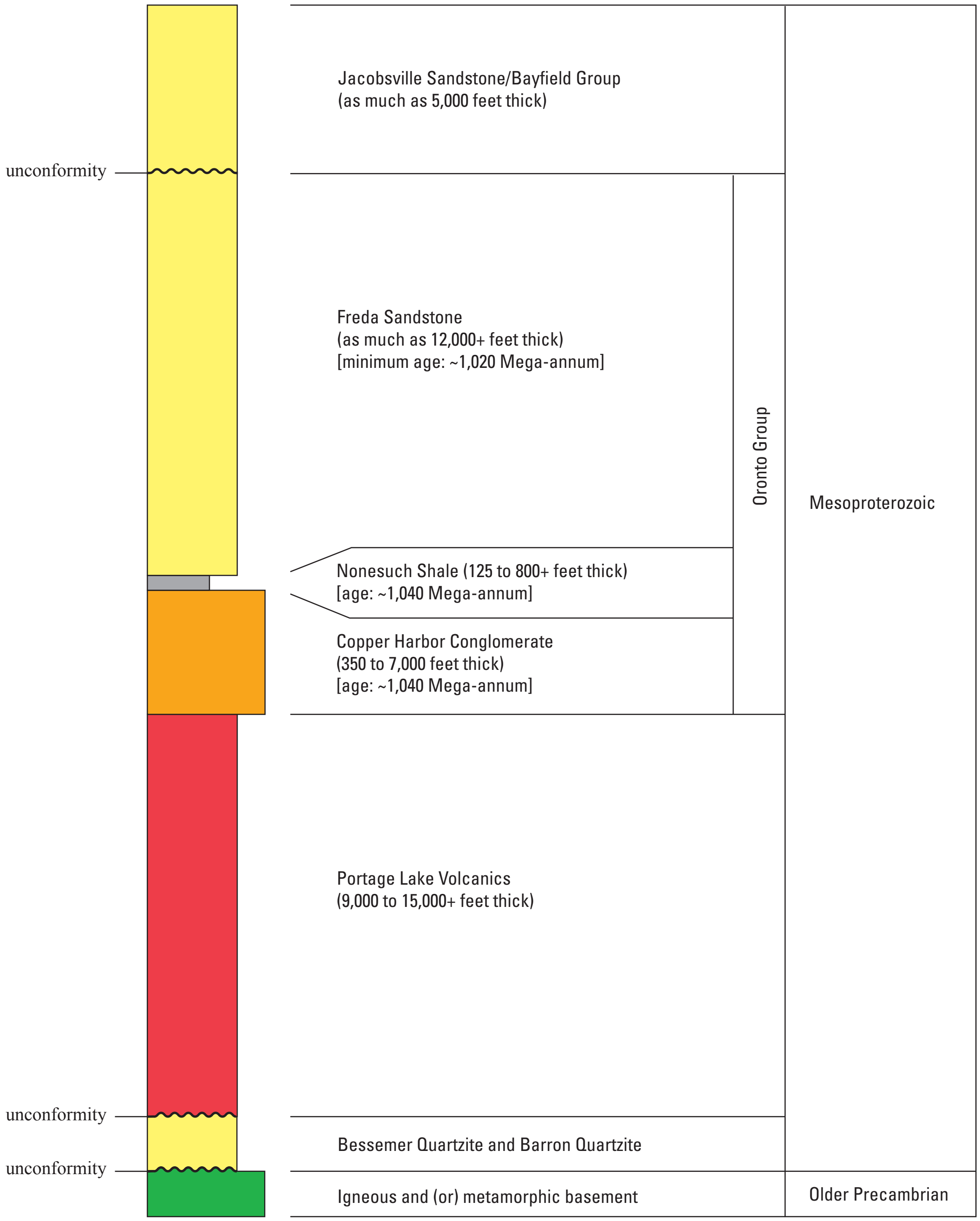


Figure 14. Stratigraphic nomenclature of the Mesoproterozoic strata in the Lake Superior region (modified from Daniels and Elmore, 1988).

Grenville front in southeastern Michigan (Hinze and others, 1975; Brown and others, 1982). This gravity anomaly is interpreted as a buried rift system that is correlative with the midcontinent rift system and associated strata in the Lake Superior region. Only the McClure Oil Company Sparks, Eckelberger, and Whightsil No. 1-8 well in Gratoit County (figs. 15 and 16) has penetrated the strata associated with the gravity anomaly in the central part of the Michigan Basin. This well, drilled in 1975, penetrated more than 5,290 ft of pre-Mount Simon Sandstone consisting of red siliciclastic strata and two thin mafic intrusions (Hinze and others, 1978; Sleep and Sloss, 1978; Daniels, 1986; Daniels and Elmore, 1988; Catacosinos and others, 1990; Catacosinos and Daniels, 1991). These red siliciclastic strata and mafic intrusions in the central part of the Michigan Basin are correlated with the Freda Sandstone and (or) Portage Lake Volcanics in the Lake Superior region (Daniels, 1986; Daniels and Elmore, 1988; Catacosinos and others, 1990; Catacosinos and Daniels, 1991). Seismic data indicate that an additional 0.9 mi or more of sedimentary strata may be present below the red siliciclastic strata (Fowler and Kuenzi, 1978).

Near the McClure-Sparks No. 1-8 well in Gratiot County, Vibroseis data collected by the consortium for continental reflection profiling reveal seismic reflectors that correlate with the gravity anomaly that defines a structural trough beneath the Michigan Basin (Brown and others, 1982). Furthermore, the Vibroseis data reveal three distinct zones of seismic characteristics (fig. 16). At a time of about 1.5 seconds (approximately 2.8 mi), there is an upper zone of layered seismic reflectors, which correspond with the base of the Cambrian Mount Simon Sandstone. Between time of about 1.5 seconds and 1.6 seconds (approximately 2.8 to 3 mi), there is an intermediate zone of relatively few seismic reflectors that is possibly equivalent to the Jacobsville Sandstone and (or) Freda Sandstone. Finally, below a time of about 1.6 seconds (approximately 3 mi), there is a lower zone of layered seismic reflectors with a total thickness of about 2 seconds (approximately 3.7 mi). This lower zone is interpreted as interstratified conglomerate, sandstone, and volcanic rocks equivalent to the Portage Lake Volcanics, Copper Harbor Conglomerate, and (or) Nonesuch Shale in the Lake Superior region. This lower zone of layered seismic reflectors fills and defines a trough that is 37 mi wide, and this correlates spatially with the mid-Michigan gravity anomaly. In the central part of the trough, the seismic reflectors in this lower zone are discontinuous. This could be attributed to disruption by volcanic intrusions, more extensive faulting, and (or) more uniform lithology with few acoustic contrasts.

Petroleum Source Rocks

The Precambrian Nonesuch TPS contains one possible petroleum source rock, the Nonesuch Shale. The known extent of the Nonesuch Shale is restricted to the western Lake Superior region (fig. 15). In the Michigan portion of the Lake Superior region, the Nonesuch Shale is found in outcrop. Dickas (1995), however, stated that the Amoco 7-22 Terra-Patrick well (fig. 15), on the south shore of Lake Superior in Wisconsin, encountered the Nonesuch Shale at depths ranging from 3,730 to 4,170 ft. Isopach data from (Dickas, 1988) show that the Nonesuch Shale in northernmost Wisconsin (Douglas, Bayfield, and Ashland Counties) ranges in thickness from 25 to 150 ft. Throughout much of the western Lake Superior region, the thickness of the Nonesuch Shale generally ranges from 125 to 800 ft. Although not confirmed, it is possible that the source rocks within the Nonesuch Shale extend into the deep subsurface beneath central Michigan (this maximum possible geographical extent is shown in fig. 12).

The possible source rocks for the petroleum are black shales within the Nonesuch Shale. Analyses of nearly 400 outcrop and shallow core samples indicate that most shale beds in the Nonesuch Shale have organic-carbon contents that are less than 0.3 weight percent, although a few thin beds of silty shale in Michigan have organic-carbon contents that range from 0.25 to 2.8 weight percent (Imbus and others, 1988; Hieshima and others, 1990; Pratt and others, 1991; Palacas, 1992). In Ontonagon County, Michigan, at the White Pine Mine, black shale beds occur within the Nonesuch Shale. These black shale beds also occur in the Nonesuch Shale in southern Bayfield County and have been reported in the subsurface from a core in northeastern Douglas County (Dickas, 1984). It is possible that the black shales in the Nonesuch Shale may be present in Wisconsin (Paull, 1986), but Nonesuch Shale equivalent strata in Minnesota has low organic-carbon content (Hatch and Morey, 1985).

Most of the available organic geochemical data on the Nonesuch Shale comes from the vicinity of the White Pine Mine, where the Nonesuch Shale is marginally mature to mature with respect to oil generation (Palacas, 1992). Maturation of the Nonesuch Shale is thought to have occurred primarily in deeper parts of the basin, and petroleum is thought to have migrated later into the vicinity of the White Pine Mine (Seglund, 1989). According to Mauk and Meyers (1990), temperatures were sufficiently high in the axial portion of the rift basin to generate hydrocarbons from the Nonesuch Shale before the initial compression associated with the Grenville orogeny (which is thought to have occurred about 100 million years after accumulation of the Nonesuch Shale). Furthermore, Mauk and Burruss (2002) stated that the lack of biodegradation of the oil from seeps at the White Pine Mine is consistent with the generation of petroleum in deeper, hotter parts of the rift followed by relatively rapid migration and entrapment. Mauk and Burruss (2002) also stated that 100 °C is a reasonable estimate of the maximum temperature at the White Pine Mine. Furthermore, thermal modeling by Mauk and Hieshima (1992) indicates that temperatures experienced by the Nonesuch Shale in the axial part of the rift basin (about 25 mi north of White Pine Mine) ranged from 140 to 300 °C. Since the first arrival of petroleum at the White Pine Mine, the oil window in this region has moved approximately 50 mi from the basin axis to the present margin of the basin at the White Pine Mine area (Mauk and Meyers, 1990).

The base map for this figure is from Nicholson and others (2004).

Figure 15. Map showing locations of outcrops of the Mesoproterozoic Nonesuch Shale (modified from Reed, 1991). McClure 1-8, McClure Sparks, Eckelberger, and Whightsil No. 1-8 well; TP, Amoco Terra-Patrick No. 7-22 well.

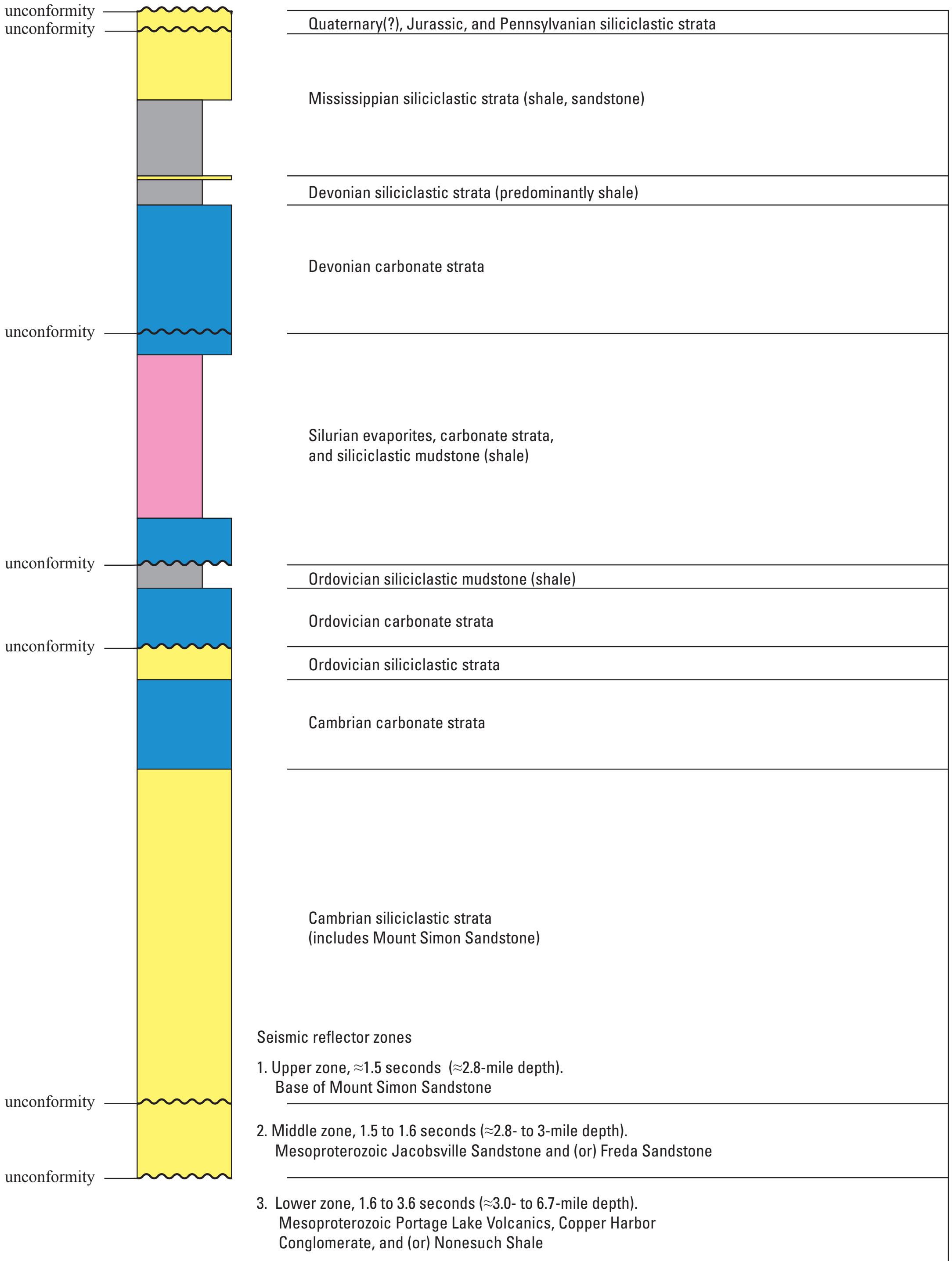


Figure 16. Generalized and seismic stratigraphy at the location of the McClure No.1-8 well, Gratiot County, Michigan (modified from Hinze and others, 1978, and Catacosinos and others, 1990). Approximate seismic signal travel time (seconds) and depth (miles) to the three layered seismic reflector zones are listed.

At the White Pine Mine in Ontonagon County, Michigan, the Nonesuch Shale is a petroliferous and metalliferous green to black siltstone, shale, and fine-grained sandstone (Daniels, 1986; Daniels and Elmore, 1988; Elmore and others, 1988). Copper sulfides, native copper, native silver, and hydrocarbons are found near the base of the Nonesuch Shale at the White Pine Mine (fig. 15). These hydrocarbons consist of active oil seeps and bitumen that represent petroleum migration (Mauk and Meyers, 1990). The bitumen occurs as inclusions within veins along faults and joints and as cement in sandstone (lithic arenite) associated with native copper (Kelly and Nishioka, 1985; Elmore and others, 1988). Liquid oil is present in primary fluid inclusions in calcite crystals in copper-iron-sulfide-bearing veins along faults that crosscut and offset shale beds in the Nonesuch Shale. Copper mineralization also occurs in sandstone in the uppermost 3 to 7 ft of the Copper Harbor Conglomerate (Kelly and Nishioka, 1985). It is postulated that the presence of organic matter in the strata reduced copper-rich fluids that migrated through the Nonesuch Shale (and also the Copper Harbor Conglomerate), resulting in copper mineralization. Using the rubidium-strontium dating technique, Ruiz and others (1984) obtained an age of 1,047 ± 35 Ma for these calcite crystals at the White Pine Mine. This age is an entrapment age and is interpreted as a minimum age for the oil at White Pine. For comparison, Dickas and Mudrey (1991), using an indirect Rb-Sr age dating technique, indicated that the maximum age of the Nonesuch Formation is 1,074 Ma.

In the Lake Superior region, thermal maturity of organic matter in the Nonesuch Shale appears to range from marginally mature to mature with respect to petroleum generation (Mauk and Meyers, 1990; Palacas, 1992) and should have primarily generated oil. Hence, any undiscovered petroleum resources in the Precambrian Nonesuch TPS should consist primarily of oil. If the Nonesuch Shale, or a stratigraphic equivalent, extends to the central part of the Michigan Basin, any undiscovered petroleum resources in the Precambrian Nonesuch TPS should consist primarily of gas. Organic matter in Nonesuch Shale equivalent strata in Minnesota is thermally very mature (gas-generation window) (Hatch and Morey, 1985).

Precambrian Nonesuch Assessment Unit

The Precambrian Nonesuch AU consists of the Precambrian Nonesuch Shale, which contains siltstones, shales, and sandstones (Daniels, 1986; Daniels and Elmore, 1988; Elmore and others, 1988). The known extent of the Precambrian Nonesuch Shale is restricted to the western Lake Superior region where the thickness of the Nonesuch Shale ranges from 125 ft in northern Wisconsin to a maximum of 800 ft in the Keweenaw Peninsula area of northern Michigan. Drilling depths along the south shore of Lake Superior range from 0 ft (outcrop) to approximately 4,000 ft. In the Lake Superior region, the Nonesuch Shale is present in the Ashland Basin, Bayfield Basin, Gogebic Basin, and Jacobsville Basin (see fig.13) (Seglund, 1989). It is possible that the Nonesuch Shale, or stratigraphically equivalent strata, are present elsewhere in the midcontinent rift system, but this has not yet been established from the limited core data that are available.

Assessment Unit Model

The Precambrian Nonesuch AU may contain conventional oil and (or) gas accumulations. The migration of petroleum from source rocks within the Nonesuch Shale is thought to have occurred during an episode of compression. This is indicated because petroleum inclusions at the White Pine Mine occur most commonly as secondary inclusions in veins that are spatially associated with thrust and tear faults that formed during compressional faulting (Mauk and Burruss, 2002). This episode of compression is associated with the Grenville orogeny (Mauk and Meyers, 1990) and with the reverse motion on the Keweenaw fault that occurred at approximately 1,060 Ma (Cannon and others, 1993).

Reservoir Characteristics

As of 2004, petroleum has not been produced commercially from the Precambrian Nonesuch AU. Potential reservoir rocks in the assessment unit include both sandstones and shales in the Nonesuch Shale. Limited analyses from two thin sections indicate that porosity in sandstones of the Nonesuch Shale is about 5 percent (Ojakangas, 1986). At the White Pine Mine, small amounts of oil have been collected from seeps in the Nonesuch Shale (Eglinton and others, 1964; Barghoorn and others, 1965; Hoering and Navale, 1987; Elmore and others, 1988; Hoering, 1988; Seglund, 1989; Mauk and Meyers, 1990; Mauk and Burruss, 2002). Petroleum is also present in the Nonesuch Shale as secondary inclusions in veins (Mauk and Burruss, 2002). Furthermore, in the Amoco 7-22 Terra-Patrick well (located on fig. 15), minor gas shows were reported from the Nonesuch Shale at depths between 3,730 and 4,170 ft (Dickas, 1995). Reservoir traps and seals are most likely to be associated with shale beds in the Nonesuch Shale. Both structural and stratigraphic traps are possible (Paul, 1986; Ojakangas, 1986).

Undiscovered Petroleum Resources

For the 2004 assessment of undiscovered, technically recoverable oil and gas resources of the U.S. portion of the Michigan Basin, the USGS identified the Precambrian Nonesuch AU but did not assess it (Swezey and others, 2005, their table 1). At the time of the assessment, no petroleum production had been established from the assessment unit, and available stratigraphic and geochemical information were insufficient to conduct a quantitative assessment.

Ordovician Foster Total Petroleum System

The Ordovician Foster TPS is based on the identification of petroleum source-rock intervals within the Ordovician Foster Formation in the central part of the Michigan Basin. The Foster Formation, a silty dolomite with minor quartz sandstone and anhydrite, is the uppermost formation of the Ordovician Prairie du Chien Group (Fisher and Barratt, 1985) (figs. 17 and 18). One assessment unit is characterized from the Ordovician Foster TPS. This assessment unit, the Ordovician Sandstones and Carbonates AU, consists of petroleum in reservoirs in the Ordovician Prairie du Chien Group, St. Peter Sandstone, and Glenwood Formation (figs. 17 and 18).

The thickness of the Lower to Middle Ordovician Foster Formation ranges from 0 to 1,700 ft in the central part of the Michigan Basin (fig. 19). Elevations on the top of the Foster Formation range from about 2,500 ft to 11,500 ft below sea level in central Michigan (fig. 20). The Foster Formation rests on top of dolomite and dolomitic siltstone that are tentatively correlated with the top part of the Prairie du Chien Group (Fisher and Barratt, 1985; Catacosinos and Daniels, 1991; Barnes and others, 1996). The Foster Formation is capped by an unconformity, above which lies the Middle Ordovician St. Peter Sandstone.

Petroleum Source Rocks

Source rocks for petroleum in the Ordovician Foster TPS are thought to be thin, shaly carbonate beds within the Lower to Middle Ordovician Foster Formation. Available organic geochemical analyses for Foster Formation samples are limited to organic-carbon analyses on 27 core samples from the Brazos State Foster No. 1 well in Ogemaw County, Michigan, and organic carbon and Rock-Eval pyrolysis analyses of eight core samples from the JEM Petroleum Bruggers No. 3–7 well in Missauke County, Michigan. Depths (surface datum) for samples from the Foster No. 1 well range from 11,645 to 12,960 ft; for samples from the Bruggers No. 3–7 well, depths range from 11,404 to 11,573 ft. The distribution of organic-carbon contents for samples from these two wells is shown in figure 21. Locations of these two wells are shown in figure 22. These organic-carbon values have not been corrected for possible generated petroleum. Organic-matter thermal maturity (based on conodont color alteration index [CAI] values from

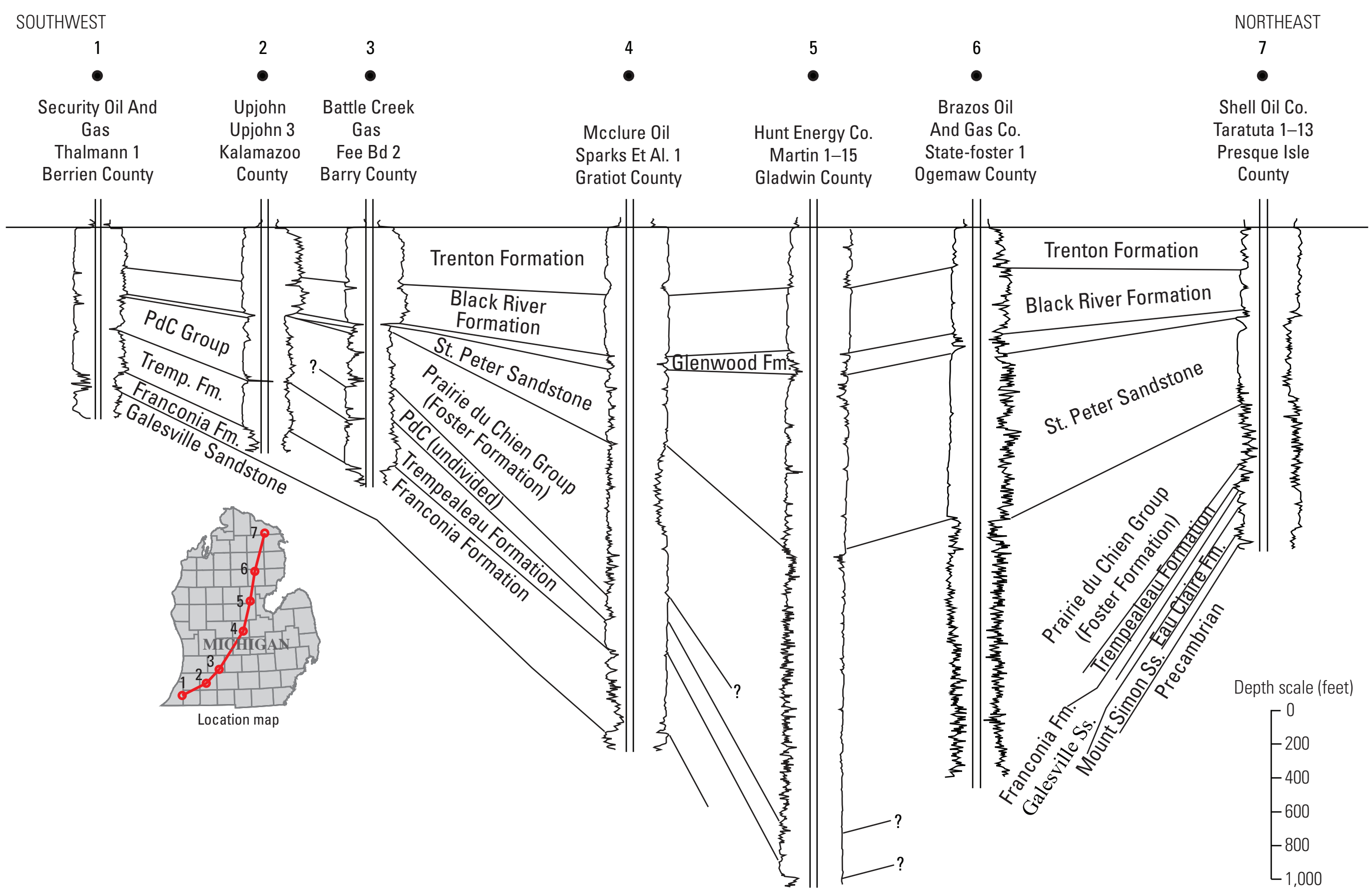


Figure 17. Southwest to northeast cross section of Ordovician and Cambrian strata in Michigan (modified from Fisher and Barratt, 1985). Cross-section datum is the top of the Middle Ordovician Trenton Formation. Horizontal distances are not to scale; scales for the gamma-ray and resistivity logs are not available. Fm., Formation; Ss., Sandstone; Tremp. Fm., Trempealeau Formation; PdC, Prairie du Chien.

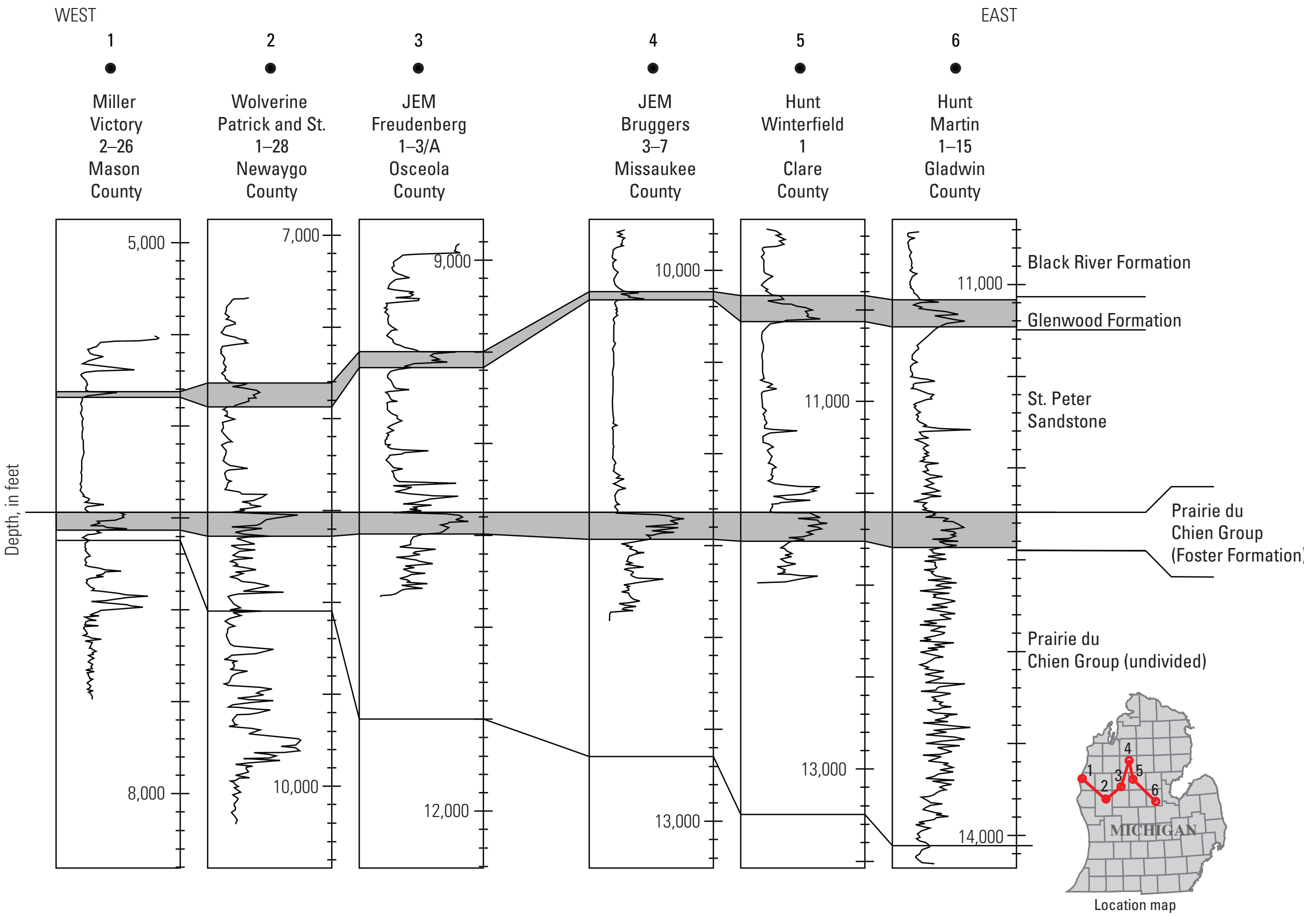


Figure 18. West to east cross section of Ordovician strata in Michigan, based on gamma-ray logs for selected wells (modified from Barnes and others, 1996). Horizontal distances are not to scale. Depth is in feet. Cross-section datum is the base of the Ordovician St. Peter Sandstone. Scale for the gamma-ray log is not available.

The base map for this figure is from Nicholson and others (2004).

Figure 19. Map of isopachs of the Lower to Middle Ordovician Foster Formation in the central part of the Michigan Basin (after Fisher and Barratt, 1985).

The base map for this figure if from Nicholson and others (2004).

Figure 20. Structure map on top of the Lower to Middle Ordovician Foster Formation in the central part of the Michigan Basin (modified from Brady and DeHaas, 1988). Southern margin of the Foster Formation is taken from Fisher and Barratt (1985).

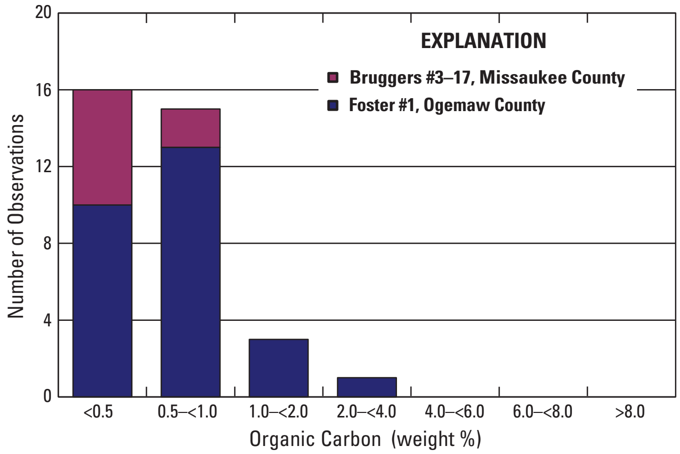


Figure 21. Histogram showing the distribution of organic-carbon contents (weight percent) for 35 core samples from the Lower to Middle Ordovician Foster Formation in the Michigan Basin. Twenty-seven of the samples are from the Brazos State Foster No. 1 well in Ogemaw County, Michigan; eight of the samples are from the JEM Petroleum Bruggers No. 3–7 well in Missaukee County, Michigan.

the underlying Prairie du Chien Group) show that these Foster Formation samples are primarily within the window of gas generation (fig. 22). Consequently, undiscovered petroleum resources in the Ordovician Sandstones and Carbonates AU would probably consist primarily of gas.

Ordovician Sandstones and Carbonates Assessment Unit

The Ordovician Sandstones and Carbonates AU includes (1) the Lower Ordovician Prairie du Chien Group, (2) the Middle Ordovician St. Peter Sandstone, and (3) the Middle Ordovician Glenwood Formation. These units consist predominantly of sandstone with some limestone, dolomite, anhydrite, and shale. The thickness of the Ordovician Sandstones and Carbonates AU ranges from approximately 200 to 1,300 ft throughout much of its extent (fig. 23); elevations at the top of the St. Peter Sandstone and (or) base of the Glenwood Formation range from about 3,000 to 11,000 ft below sea level in the center of the Michigan Basin (figs. 24 and 25). The known extents of the St. Peter Sandstone (fig. 24) and the Glenwood Formation (fig. 25) are from Nadon and others (2000).

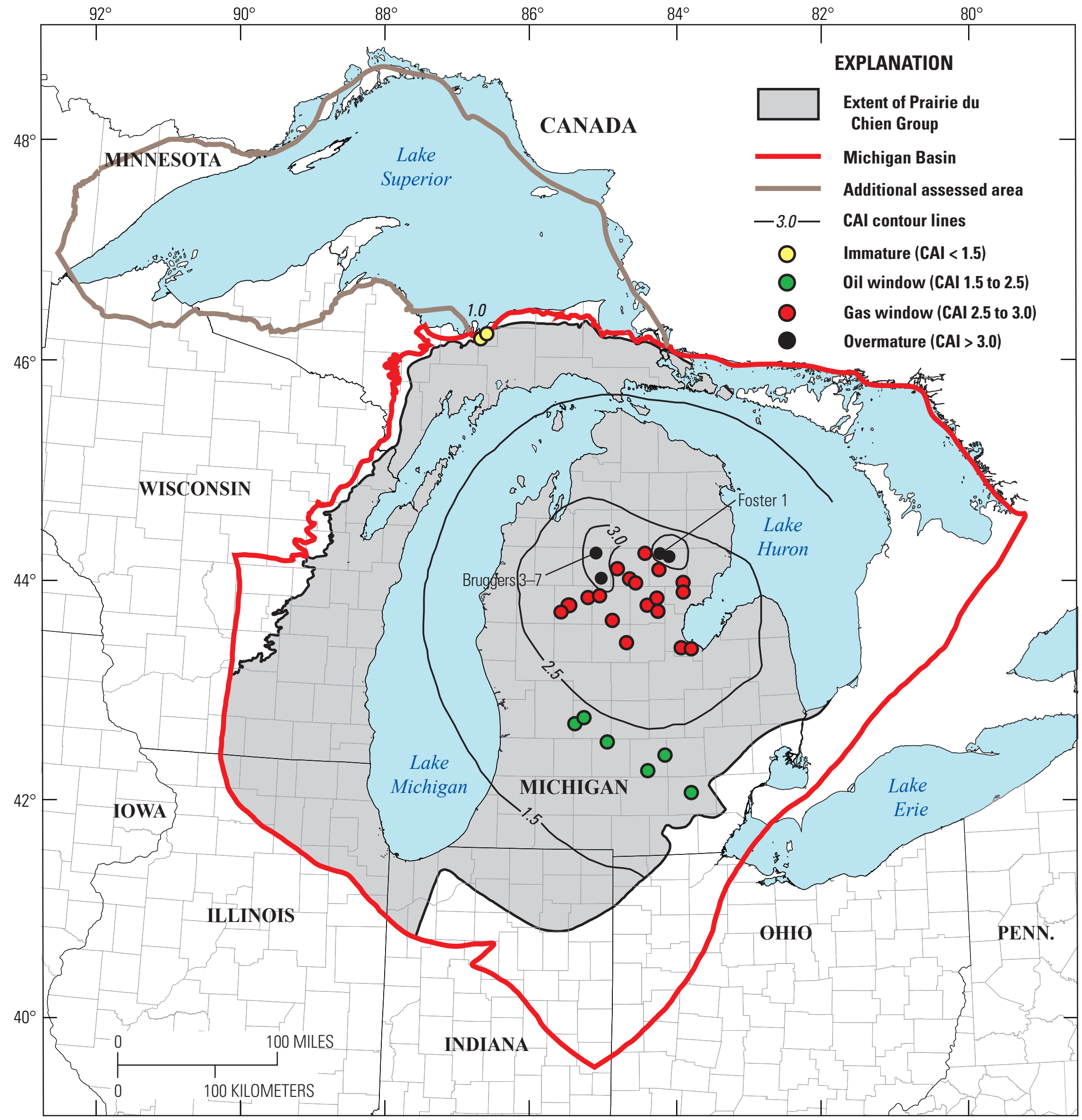
Relations of the stratigraphic units within the assessment unit are described by Catacosinos and others (1990), Drzewiecki and others (1994), Barnes and others (1996), Smith and others (1996), and Nadon and others (2000). According to these authors, the Prairie du Chien Group rests on the Upper Cambrian Trempealeau Formation. The Prairie du Chien Group is capped by an unconformity, above which lies the St. Peter Sandstone, which in turn is overlain by the Glenwood Formation (figs. 17 and 18). In Wisconsin, strata equivalent to the Prairie du Chien Group consist of the Oneota Formation and the overlying Shakopee Formation. In the subsurface of the Michigan Basin, the uppermost formation within the Prairie du Chien Group has been named the Foster Formation (Fisher and Barratt, 1985), although it is not clear whether the Foster Formation is correlative with the Shakopee Formation or whether the Foster Formation should be considered to be a separate formation that rests upon strata that are equivalent to the Shakopee Formation (Barnes and others, 1996).

In the Michigan Basin, the St. Peter Sandstone has previously been called the Bruggers Formation, the Jordan Sandstone, the “massive sandstone,” and the Prairie du Chien Sandstone (Fisher and Barratt, 1985; Harrison, 1986, 1987; Barnes and others, 1992, 1996). The upper and lower contacts of the St. Peter Sandstone are conformable in the center of the Michigan Basin and disconformable along the basin margins. On the margins of the basin, the contact between the St. Peter Sandstone and the underlying Prairie du Chien Group is an unconformity (the Sauk-Tippecanoe unconformity). The Glenwood Formation rests on the St. Peter Sandstone and is overlain by the Black River Formation. The contact of the Black River Formation with the underlying Glenwood Formation (fig. 18) is conformable and gradational in the center of the basin and disconformable along the basin margins.

The Prairie du Chien Group is a mixed carbonate-siliciclastic unit composed of sandstone, dolomite, silty to sandy dolomite, and anhydrite (Catacosinos and others, 1990; Drzewiecki and others, 1994; Barnes and others, 1996; Smith and others, 1996; Nadon and others, 2000). The thickness of the Prairie du Chien Group ranges from 0 to 1,300 ft in the Michigan Basin (fig. 26). The Prairie du Chien consists primarily of sandstone on the northern margin of the basin, whereas the unit consists primarily of dolomite on the southern margin of the basin (Maslowski, 1987). In the central part of the basin, the Prairie du Chien grades upward from dolomite into a gray- to black-dolomitic siltstone and shale with anhydrite (Foster Formation).

The St. Peter Sandstone, a predominantly quartzarenite sandstone, interfingers with dolomite and shale in the lower and middle portions of the formation (Catacosinos and others, 1990; Drzewiecki and others, 1994; Barnes and others, 1996; Nadon and others, 2000). The thickness of the St. Peter Sandstone ranges from about 66 to 130 ft in outcrop in Wisconsin and to as much as 984 ft in the subsurface in Michigan (fig. 27). In south-central Wisconsin and western Michigan, the St. Peter Sandstone consists primarily of medium-grained to fine-grained nonbioturbated sandstone, whereas in central Michigan much of the upper St. Peter Sandstone is intensely bioturbated. Additional descriptive information on the St. Peter Sandstone may be found in Dapples (1955), Barnes and others (1992), and Popov and others (2001).

The Glenwood Formation includes (1) black to green shale; (2) gray, muddy dolomite with thin beds of sandstone; and (3) limestone. The thickness of the Glenwood Formation ranges from approximately 16 ft in outcrop in Wisconsin



The base map for this figure is from Nicholson and others (2004).

Figure 22. Map showing the thermal maturity of organic matter in the Lower Ordovician Prairie du Chien Group in the central part of the Michigan Basin based on conodont color alteration index (CAI). The contour interval is 0.5 CAI; contours are based on limited data. With respect to petroleum generation, CAI <1.5 = immature; CAI from 1.5 to 2.5 = oil window; CAI from 2.5 to 3.0 = gas window; CAI >3.0 = overmature. Bruggers 3–7 = JEM Petroleum Bruggers No. 3–7 well, Missaukee County, Michigan; Foster 1 = Brazos State Foster No. 1 well, Ogemaw County, Michigan.

The base map for this figure is from Nicholson and others (2004).

Figure 23. Map of isopachs of the Ordovician Sandstones and Carbonates Assessment Unit (AU) in the central part of the Michigan Basin (modified from Maslowski, 1987).

The base map for this figure is from Nicholson and others (2004).

Figure 24. Structure map on top of the Middle Ordovician St. Peter Sandstone in the central part of the Michigan Basin (modified from Martinson, 1987).

The base map for this figure is from Nicholson and others (2004).

Figure 25. Structure map on the base of the Middle Ordovician Black River Formation and (or) the top of the Middle Ordovician Glenwood Formation (where it is present) in the central part of the Michigan Basin (modified from Fisher and Barratt, 1985).

The base map for this figure is from Nicholson and others (2004).

Figure 26. Map of isopachs of the Lower Ordovician Prairie du Chien Group in the central part of the Michigan Basin (modified from Maslowski, 1987).

The base map for this figure is from Nicholson and others (2004).

Figure 27. Map of isopachs of the Middle Ordovician St. Peter Sandstone in the central part of the Michigan Basin (constructed from data in Nadon and others, 2000).

to 197 ft in the subsurface in Michigan (Nadon and others, 2000). In south-central Wisconsin and western Michigan, the Glenwood Formation is a bioturbated, clay-rich sandstone that is overlain by bioturbated coarse-grained to medium-grained sandstone with some phosphatic granules and sandy dolomite. In central Michigan, much of the Glenwood Formation consists of intensely bioturbated carbonate and phosphatic shale. The phosphate causes the Glenwood Formation to display a strong response in gamma-ray logs.

Assessment Unit Model

The Ordovician Sandstones and Carbonates AU contains conventional petroleum accumulations. The source rocks for the petroleum are in the Foster Formation (the uppermost formation within the Prairie du Chien Group). Petroleum generation and migration from the Foster Formation began during the Late Devonian (coincident with the Acadian orogeny), when the Foster Formation entered the oil window in the deepest part of the basin. Subsequently, during the Pennsylvanian and Permian (coincident with the Alleghanian orogeny), most of the Foster Formation entered the gas window and continued to generate petroleum. Today, the thermal maturity of organic matter in most of the Foster Formation is within the gas window. Both the Middle Ordovician Collingwood Shale and the overlying Upper Ordovician Utica Shale may act as reservoir seals to inhibit migration of the gas. The Black River Formation, which lies below the Utica Shale, is composed primarily of low-porosity limestone and may also act as a reservoir seal.

Although known reservoirs within the Prairie du Chien Group, St. Peter Sandstone, and Glenwood Formation are typically located on anticlines beneath Devonian-age structural features, most of these reservoirs produce from porosity and permeability traps in sandstone (Maslowski, 1987; Johnson, 1989a,b; Catacosinos and others, 1990). In the St. Peter Sandstone, gas has been recovered from two main sandstone intervals, one near the middle and one near the top of the formation (Harrison, 1987; Catacosinos and others, 1990; Harris and others, 1992; Nadon and others, 2000). In the Glenwood Formation (Catacosinos and others, 1990; Drzewiecki and others, 1994), petroleum reservoirs are sandstone beds interbedded with argillaceous carbonate, which may act as reservoir seals. Regionally extensive, low-permeability and low-porosity strata (either carbonate or banded sandstone cemented by quartz or dolomite) may also act as reservoir seals in the Glenwood Formation. Additional reservoir traps and seals may involve stratigraphic pinchouts where sandstones within the Prairie du Chien Group grade southward into carbonate and (or) where the strata are removed by erosion.

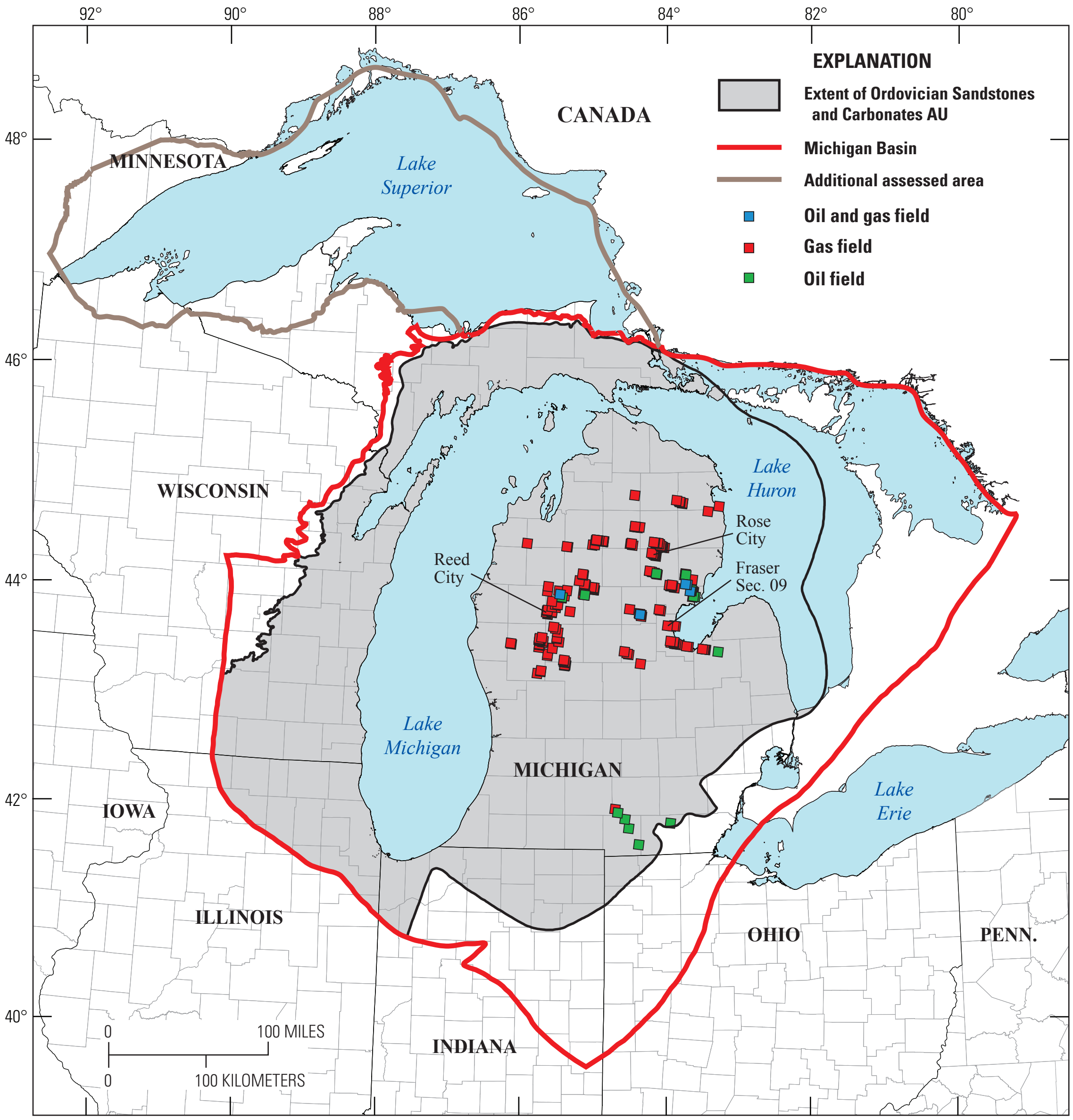
Reservoir Characteristics

Most reservoirs in the Prairie du Chien Group, St. Peter Sandstone, and Glenwood Formation have produced gas and natural gas liquids, although oil has been produced from a few fields (fig. 28). Many of the known fields are on northwest-trending anticlines that range from 1 to 7 mi in length (Johnson, 1989a,b; Catacosinos and others, 1990). The fields on the west side of the Michigan Basin are coincident with the western edge of the Precambrian rift system. Fields on the western side of the basin are typically characterized by 20 to 80 ft of structural closure, whereas fields on the eastern side of the basin are typically characterized by 100 to 200 ft of closure. In some instances, potential petroleum reservoirs have been found off-structure, but these are typically filled with saltwater rather than petroleum (Harrison, 1987). Furthermore, some structurally high positions have not yielded production because of low porosity and permeability (Harrison, 1987).

Reservoir quality is greatly influenced by original depositional characteristics and by diagenetic fabrics (Harrison, 1987; Catacosinos and others, 1990; Drzewiecki and others, 1994; Winter and others, 1995; Nadon and others, 2000). In the St. Peter Sandstone, well-sorted, coarser grained sandstone typically has abundant syntaxial quartz cement, resulting in low-permeability and poor-quality reservoirs. In contrast, the more poorly sorted, finer grained sandstone in the St. Peter Sandstone typically has abundant secondary porosity (caused by dissolution of carbonate cement), resulting in higher permeability and better quality reservoirs. In particular, burrowed zones in the St. Peter Sandstone tend to have greater secondary porosity, in places exceeding 20 percent (Harrison, 1987). In the Glenwood Formation, however, the better reservoirs consist of cross-bedded and skolithos-burrowed sandstone (6 to 10 percent average porosity, 10 to 20 millidarcy [md] average permeability, and 25 to 35 percent water saturation on structure), whereas the poorer quality reservoirs consist of shaly sandstone with low permeability (0.5 to 5 md) and high water saturations (55 to 75 percent) caused by excessive clay in the pore networks (Harris and others, 1992). Bahr and others (1994) provide a variety of charts that show pressure versus depth for the Prairie du Chien Group, permeability versus depth for the St. Peter Sandstone, and permeability versus depth for the Glenwood Formation.

The State of Michigan has adopted 640 acres as the optimum well spacing that will economically and efficiently drain a unit of gas below the top of the Glenwood Shale (Anonymous, 1986). In the Prairie du Chien Group, the average well has 38 ft of net pay, 11.4 percent porosity, 38 percent water saturation, and what appears to be depletion drive (Anonymous, 1986). In the St. Peter–Glenwood interval, porosity ranges from zero to 21 percent, and permeability ranges from 0.001 to 4 md over relatively short intervals (Harrison, 1987; Catacosinos and others, 1990; Harris and others, 1992; Nadon and others, 2000). Recovery factors in St. Peter reservoirs range from 55 percent in the Falmouth field, Missaukee County, to 80 percent in the Woodville field, Newaygo County (Barnes and others, 1992).

In the deepest part of the basin, some overpressured zones are present within the St. Peter Sandstone and Glenwood Formation (Bahr and others, 1994, Nadon and others,



The base map for this figure is from Nicholson and others (2004).

Figure 28. Map showing the locations of oil and gas fields that produce from reservoirs in the Ordovician Sandstones and Carbonates Assessment Unit (AU) (Prairie du Chien Group, St. Peter Sandstone, and Glenwood Formation) in the U.S. portion of the Michigan Basin (from U.S. Geological Survey Web site http://energy.cr.usgs.gov/oilgas/noga). Identified fields are discussed in the text.

2000). In places, pressures in these overpressured zones are up to 650 pounds per square inch (lb/in^2) above the hydrostatic gradient. The largest area of overpressure is located west and north of Saginaw Bay (Bahr and others, 1994, Winter and others, 1995).

The Rose City field in Ogemaw County (fig. 28) is an example of a field that produces gas from Ordovician sandstone (Maslowski, 1987; Tinker and others, 1991). Production is from a 250-ft interval of Ordovician sandstone that includes the Glenwood Formation, St. Peter Sandstone, and Prairie du Chien Group. Most of the pay zone is likely within the St. Peter Sandstone. The Ordovician sandstone production was discovered in 1986; the field consists of five producing wells on 640-acre spacing, located on an anticline that dips steeply to the north. The reservoir interval includes several stacked coarsening-upward sequences that contain cross-bedded sandstone, skolithos-burrowed sandstone, and graded, parallel-bedded sandstone. The crossbedded sandstone and skolithos-burrowed sandstone generally have excellent reservoir quality, whereas the graded, parallel-bedded sandstone has poor to good reservoir quality. The thickness of individual reservoir beds ranges from less than 6 in. to 6 ft, and the reservoir beds have an average porosity of 10 percent. Water drive is present in the zones of greater permeability.

The Reed City field in Osceola County (fig. 28) produces significant quantities of gas from the St. Peter Sandstone. In this field, which consists of five wells, the depth (surface datum) to top of pay interval is 9,589 to 9,680 ft; initial production was from 2.4 to 7.3 million cubic feet of gas (MMCFG) per day, with 2 to 40 barrels of natural gas liquids (condensate) (BNGL) per MMCFG (Harrison, 1987; Catacosinos and others, 1990).

Petroleum Geochemistry

A whole-oil gas chromatogram for a gas condensate collected from a well producing from a reservoir at a depth of 11,640 ft (surface datum) in the Lower Ordovician Prairie du Chien Group is shown in figure 29**.** The location of the well, the State Fraser and Geno No. 1–18 well, Fraser Sec. 09 field, Bay County, Michigan, is shown on figure 28. The hydrocarbon distribution in this sample is characterized by an odd-carbon predominance in the n-C_{14} to n-C_{22} alkanes and relatively low amounts of isocyclic compounds including pristane and phytane. The carbon preference index (CPI, modified from Bray and Evans, 1961) is between n-C_{20} and n-C_{26} is 1.17, the pristane/phytane ratio is 1.4, and the pristane/n-C_{17} ratio is 0.07 (all values are from measurements of peak height).

The chemical compositions (N_2 mole percent, CO_2 mole percent, H_2S mole percent, ethane/isobutane mole percent/mole percent, and gas wetness percent) of 82 natural gas samples collected from wells producing from the Prairie du Chien Group and the St. Peter Sandstone in the central part of the Michigan Basin are summarized in table 1. The data in table 1 are from Moore and Sigler (1987), Hamak and Sigler (1991), and two data sets, Michigan Oil and Gas Well Gas Analyses Data and Michigan Public Service Commission MichCon “TIPS” Data from the Michigan Geological Repository for Research and Education at Western Michigan University (http://wsh060.westhills.wmich.edu/MGRRE/data/). The data in the geographic distribution plot shown in figure 30 were calculated from these data sets.

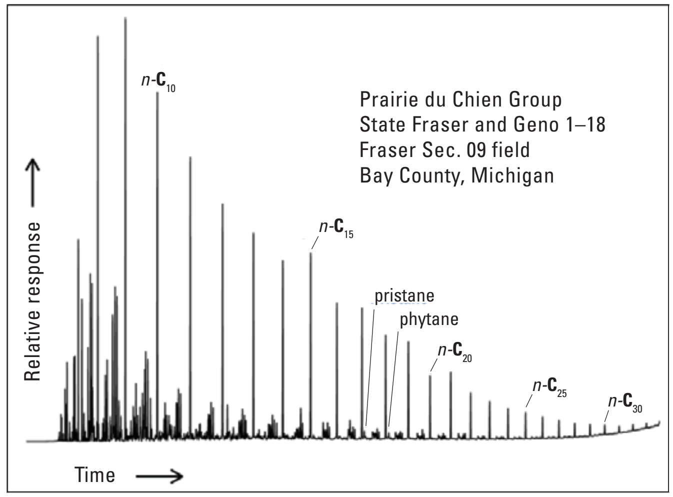
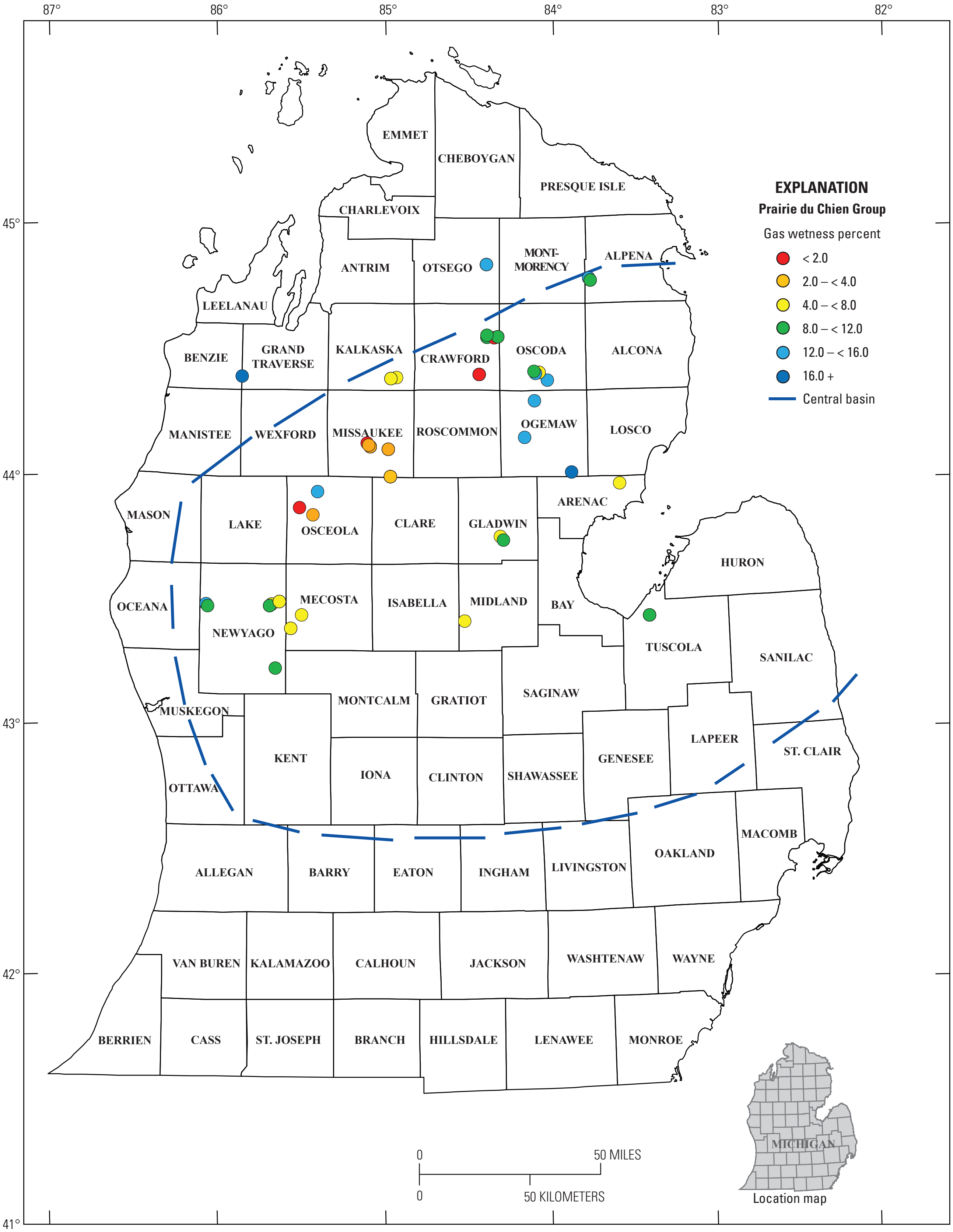


Figure 29. Whole-oil gas chromatogram for a gas condensate collected from a well producing from a reservoir in the Lower Ordovician Prairie du Chien Group (State Fraser and Geno No. 1–18 well, Fraser Sec. 09 field), Bay County, Michigan. Reservoir depth is 11,640 feet.

The gas compositions summarized in table 1 are characterized by very low H_2S contents (median <0.01 mole percent), low CO_2 contents (median = 0.11 mole percent), low N_2 contents (median = 2.1 mole percent), low gas wetness (median = 6.8 percent), and highly variable ethane/isobutane ratios (range = 1.5 to 230). The geographic distribution of gas wetness (percent) for the 82 natural gas samples is shown in figure 30. No apparent pattern of gas wetness exists with respect to position in the basin or depth to the top of the Prairie du Chien Group. Similarly, no apparent pattern exists for the other gas components summarized in table 1.

Undiscovered Petroleum Resources

In the 2004 assessment of the U.S. portion of the Michigan Basin, the USGS assessed the Ordovician Sandstones and Carbonates AU as a conventional petroleum accumulation. This assessment unit was considered to be primarily gas prone, and the undiscovered fields were assumed to be only gas fields. For the gas fields, the estimated volumes of undiscovered, technically recoverable natural gas resources are 149 BCGF at the 95-percent certainty level, 524 BCFG at the 50-percent certainty level, 1.07 trillion cubic feet of gas (TCFG) at the 5-percent certainty level, and a mean of 559 BCFG. For natural gas liquids, the estimated volumes are



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 30. Map showing the geographic distribution of gas wetness (in percent [%]) for 82 natural gas samples collected from wells producing from the Lower Ordovician Prairie du Chien Group and Middle Ordovician St. Peter Sandstone in the central part of the Michigan Basin. Gas wetness percent = 100 × (1– [C_1 mole percent/ΣC_1–C_5 mole percent]).

Table 1. Statistical summary of the chemical compositions of 82 natural gas samples collected from wells producing from the Lower Ordovician Prairie du Chien Group and Middle Ordovician St. Peter Sandstone primarily in Clare, Mecosta, Missaukee, Newyago, Ogemaw, Osceola, and Oscoda Counties in central Michigan.

[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	82	82	62	74	82
Median	2.1	0.11	<0.01	13	6.8
Average, Standard deviation	3.0 ± 2.8	0.6 ± 1.6	0.01 ± 0.09	40 ± 55	8.0 ± 6.7
Range	0.2–14	<0.01–9.9	<0.01–0.7	1.5–230	0.6–37

5.74 million barrels of natural gas liquids (MMBNGL) at the 95-percent certainty level, 21.4 MMBNGL at the 50-percent certainty level, 48.2 MMBNGL at the 5-percent certainty level, and a mean of 23.4 MMBNGL (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).

For the assessment calculations, a minimum grown field size of 0.5 MMBO equivalent was used for oil fields, and a minimum grown field size of 3 BCFG was used for gas fields. As of 2004, the Ordovician Sandstones and Carbonates AU contained three known oil fields and 39 known gas fields with grown field sizes exceeding the minimum field size. Also as of 2004, the assessment unit was estimated to have produced a cumulative 585 BCFG in the State of Michigan (fig. 10). The numbers of undiscovered accumulations greater than the minimum grown field size were estimated as follows: minimum = 1 gas field, mode = 30 gas fields, and maximum = 100 gas fields. The sizes of undiscovered accumulations greater than the minimum grown field size were estimated as follows: minimum = 3 BCFG, median = 8 BCFG, and maximum = 80 BCFG.

Ordovician to Devonian Composite Total Petroleum System—Part I

The Ordovician to Devonian Composite TPS is defined by the presence of three different petroleum source-rock intervals and evidence for significant vertical petroleum migration and commingling of petroleum (oils and natural gases) through much of the Ordovician through Devonian stratigraphic section. The three petroleum source-rock intervals are (1) Middle Ordovician Trenton Formation and Collingwood Shale, (2) Middle Devonian Detroit River Group (Amherstburg and Lucas Formations), and (3) Upper Devonian Antrim Shale (fig. 5).

Despite some uncertainty regarding the timing of petroleum migration, there is evidence for at least one episode of petroleum leakage from Ordovician source rocks through evaporite beds of the Upper Silurian Salina Group into Middle Devonian carbonate strata (Hatch and others, 2005). The evidence for petroleum leakage includes the following. (1) Presence of oils, that originated in Middle Ordovician petroleum source rocks, in Middle Devonian carbonate reservoirs overlying the Salina Group evaporite beds in the central part of the Michigan Basin. The Middle Ordovician source-rock origin of these oils is shown by their saturated hydrocarbon distributions, which are dominated by the geochemical signature of *Gloeocapsamorpha prisca* (an organic-walled microfossil of Cambrian and Ordovician age) (Jacobson and others, 1988). (2) Many of the oil reservoirs in the central part of the Michigan Basin (both above and below the Salina Group evaporite beds) are located along northwest-trending fractures, which are interpreted as flower structures controlled by reactivated deep basement faults. (3) In some Middle Ordovician and Middle Devonian carbonate reservoirs, northwest-trending fractures are associated with minerals that are typical of hydrothermal fluid flow (for example, baroque dolomite, barite, fluorite, galena, and sphalerite). In addition, chemical analyses of natural gases in Lower Silurian Burnt Bluff Group reservoirs are similar to analyses of natural gases from reservoirs in the Ordovician Sandstones and Carbonates AU lower in the section (see discussion in the Silurian Burnt Bluff AU section). These similarities support an additional source of migrated petroleum, namely the Lower to Middle Ordovician Foster Formation.

Six assessment units are identified within the Ordovician to Devonian Composite TPS. These are (1) Ordovician Collingwood Shale Continuous Gas AU, (2) Ordovician Trenton/Black River AU, (3) Silurian Burnt Bluff AU, (4) Middle Devonian Carbonates AU, (5) Devonian Antrim Continuous Oil AU, and (6) Devonian to Mississippian Berea/Michigan Sandstones AU. Of these six assessment units, two contain petroleum derived from source rocks within the Trenton Formation and (or) Collingwood Shale. These two assessment units, the Trenton/Black River AU and the Collingwood Shale Continuous Gas AU, are described in this section. A third assessment unit, the Silurian Burnt Bluff AU, may also contain petroleum derived from source rocks in the Foster Formation lower in the Ordovician section. This assessment unit is also described in this section.

The other three assessment units of the Ordovician to Devonian Composite TPS, Middle Devonian Carbonates AU, Devonian Antrim Continuous Oil AU, and Devonian to Mississippian Berea/Michigan Sandstones AU, might contain petroleum derived from one, or mixtures of two or three of the petroleum source-rock intervals in the Ordovician to Devonian Composite TPS. In other words, reservoirs in the Middle Devonian Carbonates AU might contain commingled petroleums derived from source-rock intervals within the Trenton Formation and Collingwood Shale, the Detroit River Group (Amherstburg and Lucas Formations) and (or) the Antrim Shale. Higher in the stratigraphic section, source rocks within the Antrim Shale would have contributed petroleum to the Devonian Antrim Continuous Oil AU and to the Devonian to Mississippian Berea/Michigan Sandstones AU. The Middle Devonian Carbonates AU is described in the section Ordovician to Devonian Composite Total Petroleum System—Part II, whereas the Devonian Antrim Continuous Oil AU and Devonian to Mississippian Berea/Michigan Sandstones AU are discussed in the section Ordovician to Devonian Composite Total Petroleum System—Part III.

Middle Ordovician Petroleum Source Rocks

Petroleum source rocks in this interval are thin organic-matter-rich shales near the top of the Trenton Formation and shales within the overlying Collingwood Shale. The Trenton Formation rests conformably on the Middle Ordovician Black River Formation and is overlain by the Collingwood Shale and (or) the Upper Ordovician Utica Shale. The Collingwood Shale rests conformably on the Trenton Formation and is overlain by gray to dark-gray Utica Shale (fig. 31).

The beds of organic-rich shale in the upper part of the Trenton Formation range in thickness from approximately 0.2 to 6 in., and they are apparently present throughout the Michigan Basin. In contrast, the thickness of the Collingwood Shale ranges from zero to about 36 ft, and as shown by the thickness contours in figure 32, the unit is present only in the northern part of the basin. The Collingwood Shale is found in outcrop in Ontario, Canada, and elevations at the top of the Trenton Formation and (or) base of the Collingwood Shale range from about 500 ft above sea level on the margins of the basin to 10,000 ft below sea level in central Michigan (fig. 33).

The identification of the Trenton Formation and the Collingwood Shale as petroleum source rocks is consistent with the work of Burgess (1960) who stated that the source rock for the oil in the various Trenton fields is believed to be the Trenton Formation itself, as well as the Utica Shale. For many years, the Utica Shale was thought to be the source rock for petroleum within the Trenton Formation. Geochemical analyses by Cole and others (1987), however, show that the Utica Shale does not contain appreciable amounts of organic matter, and that the Middle Ordovician Point Pleasant Formation (Collingwood Shale equivalent in Ontario) is much more likely to be the source rock for petroleum in the Trenton fields. This conclusion is supported by the work of Russell and Telford (1984) who reported typical organic-carbon contents of 6–8 percent in the Collingwood Shale, with up to 12 percent organic carbon in some places. Likewise, Hiatt and Nordeng (1985) indicated that the Utica Shale was not a source of Trenton oil, at least in the northern part of the Michigan Basin, and that the Collingwood Shale and organic-rich shale beds within the Trenton Formation are the most likely sources for the oils (see also Powell and others, 1984).

For the Albion-Scipio field in southern Michigan (location shown in figs. 1 and 39), Reed and others (1986) stated that the oil source rocks appear to be thin, discontinuous, dark organic-rich shale laminae that are distributed throughout the Trenton and Black River Formations. They reported that some of these laminae have organic-carbon contents of 20–25 percent. Hurley and Budros (1990) also thought that the thin shale beds in the Trenton and Black River Formations were the primary sources for oil produced in the Albion-Scipio and Stoney Point fields. For many of these shale beds, they reported average organic-carbon contents of 0.5–1.5 percent; maximum organic-carbon contents were 20–25 percent.

Published analyses of organic-carbon contents for the Trenton Formation and Collingwood Shale are limited to the data in Powell and others (1984) and Snowdon (1984). The distribution of organic-carbon contents for 35 samples from these two publications is shown in figure 34. The Collingwood Shale samples are from Ontario, Canada, where the organic matter is thermally immature to marginally mature with respect to petroleum generation; hence, there was no need to correct the organic-carbon values as a result of increased thermal maturity. With respect to petroleum generation, organic-rich shales in the upper part of the Trenton Formation and in the Collingwood Shale are within the gas-generation window in the central part of the Michigan Basin and within the oil-generation window on the margins of the basin (fig. 35).

Ordovician Trenton/Black River Assessment Unit

The Ordovician Trenton/Black River AU consists of carbonate strata with some beds of shale, chert, and volcanic ash within the Black River Formation and the overlying Trenton Formation. The thickness of the Ordovician Trenton Formation and Black River Formation in the central part of the Michigan Basin ranges from about 300 to 1,000 ft (fig. 36), and the elevation at the top of the Trenton Formation ranges from about 500 ft above sea level on the margins of the basin to 10,000 ft below sea level in central Michigan (fig. 33).

As described by Hiatt and Nordeng (1985), Keith (1985a), Wilson and Sengupta (1985), Catacosinos and others (1990), and Hurley and Budros (1990), the Black River Formation rests conformably on the Glenwood Formation and is overlain by the Trenton Formation. The Trenton Formation,

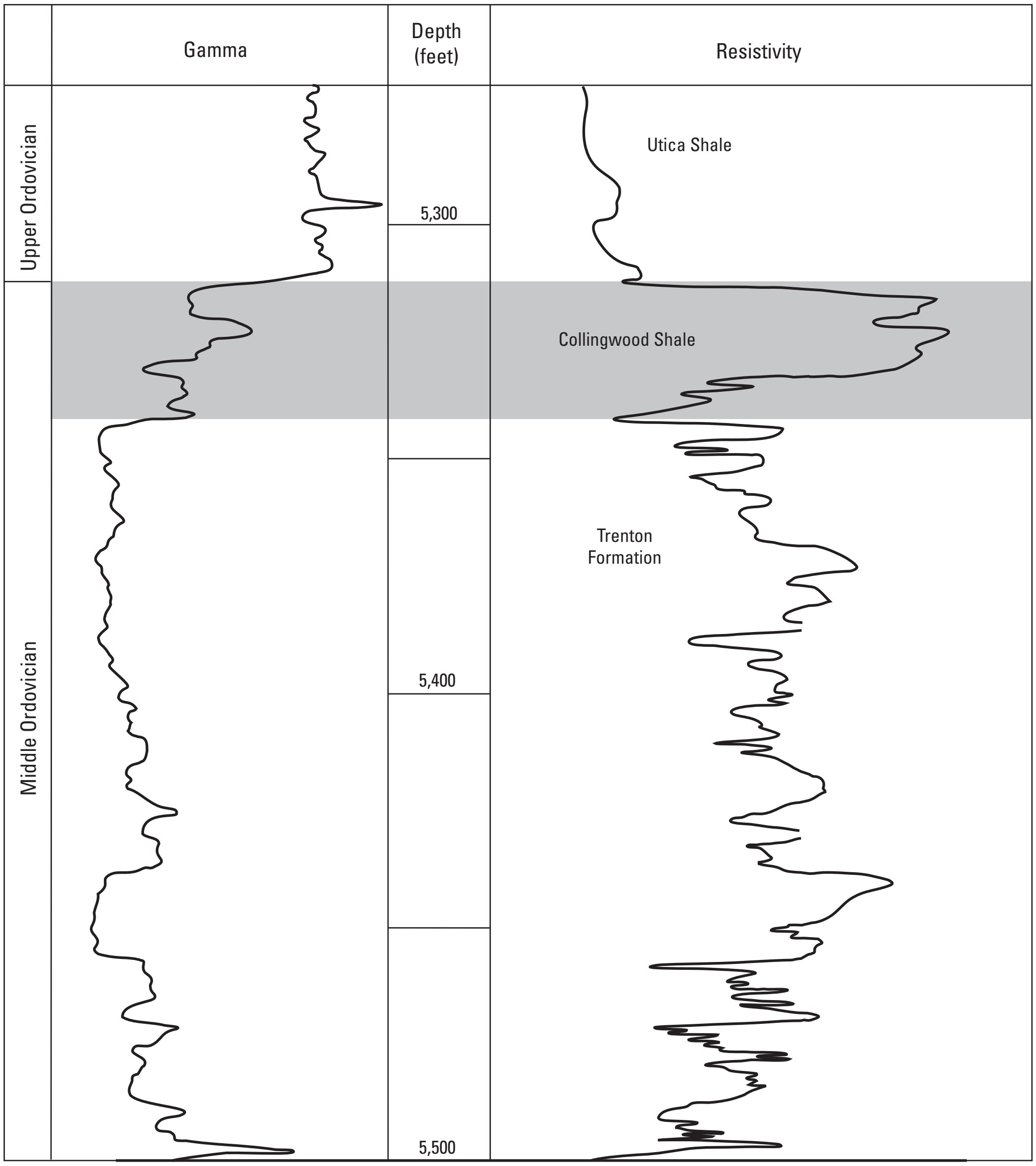
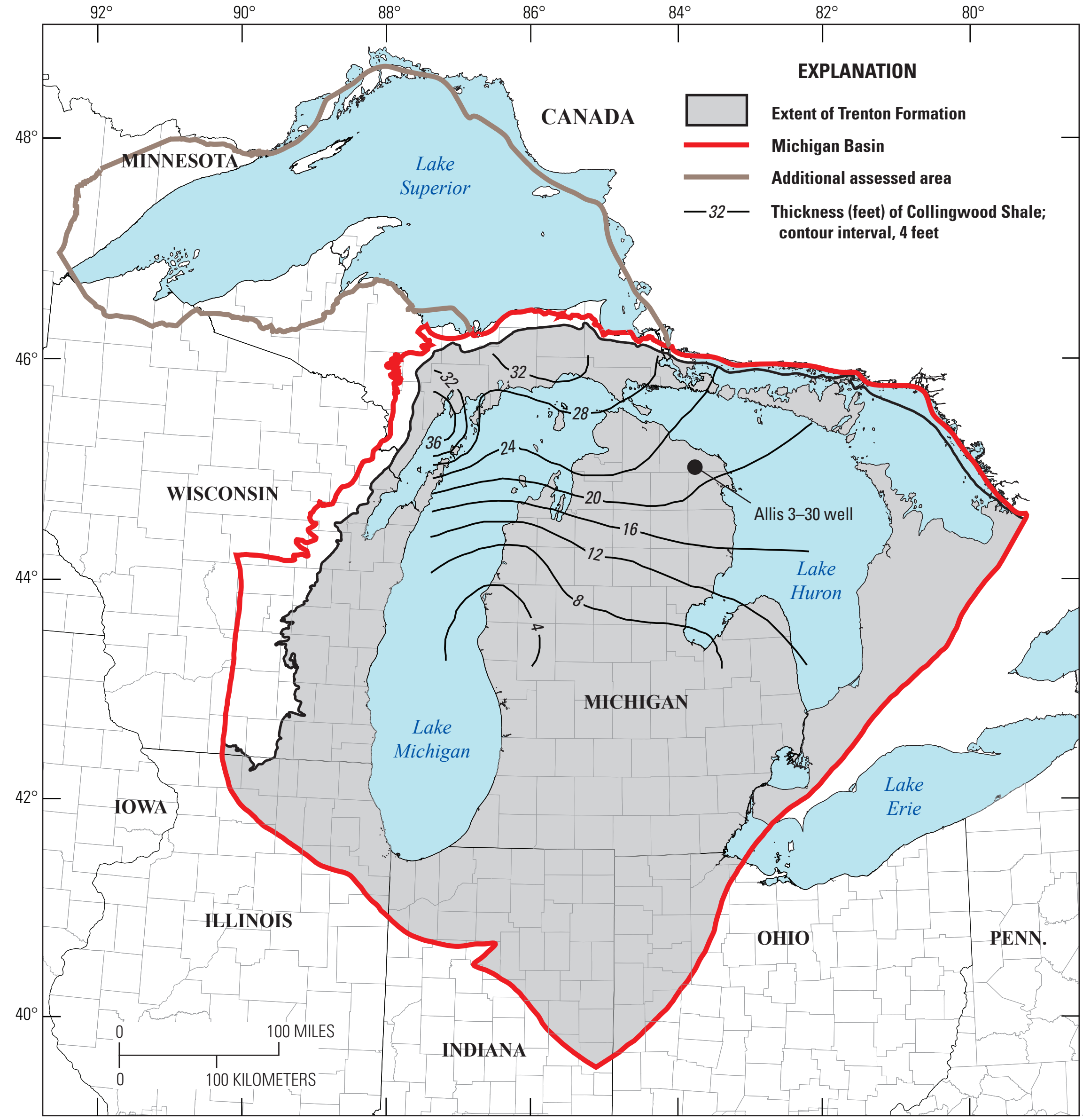
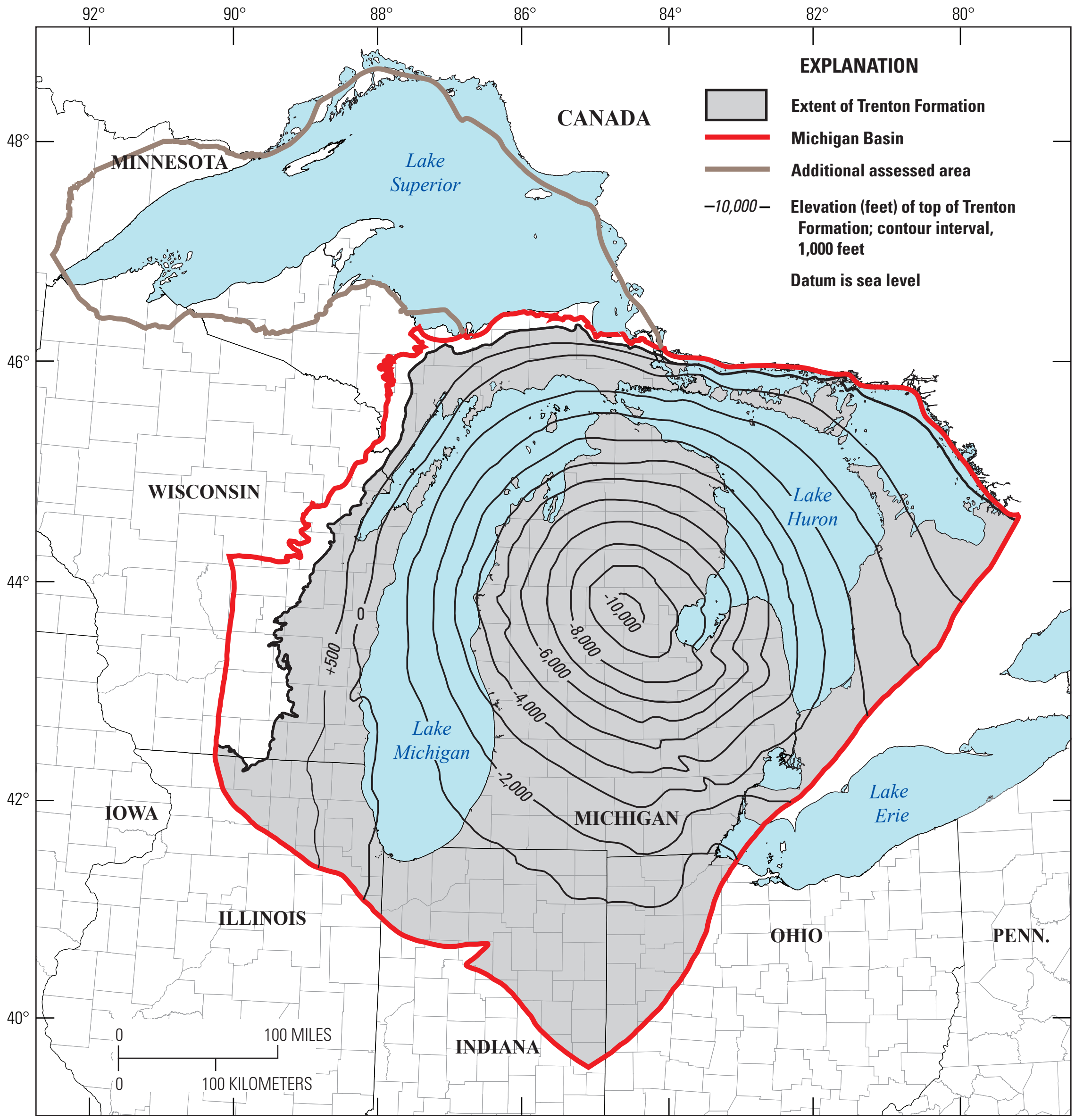


Figure 31. Interpretation of well logs from the Allis No. 3-30 well in Presque Isle County, Michigan, showing the upper part of the Middle Ordovician Trenton Formation, the Middle Ordovician Collingwood Shale, and the lower part of the Upper Ordovician Utica Shale (modified from Hiatt and Nordeng, 1985). Scales for the gamma-ray and resistivity logs are not given. Well location is shown in figure 32.



The base map for this figure is from Nicholson and others (2004).

Figure 32. Map of isopachs of the Middle Ordovician Collingwood Shale in the central part of the Michigan Basin (modified from Hiatt and Nordeng, 1985).



The base map for this figure is from Nicholson and others (2004).

Figure 33. Structure map on top of the Middle Ordovician Trenton Formation and (or) base of the Middle Ordovician Collingwood Shale in the central part of the Michigan Basin (from Keith and Wickstrom, 1992).

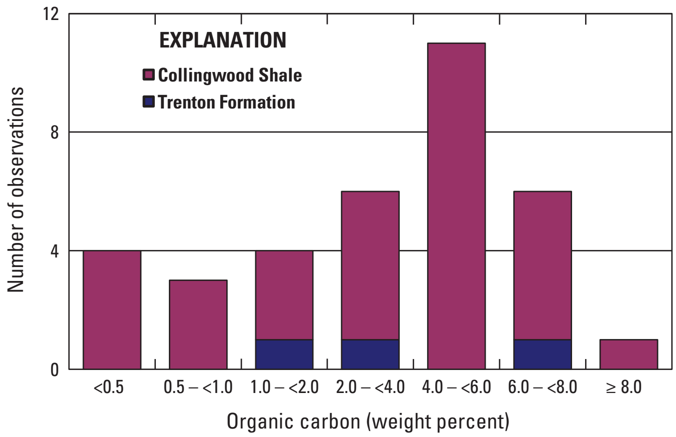


Figure 34. Histogram showing the distribution of organic-carbon contents for 35 core samples from the Middle Ordovician Collingwood Shale and Trenton Formation in the Michigan Basin (Powell and others, 1984; Snowdon, 1984). The Collingwood Shale samples are from southern Ontario, Canada.

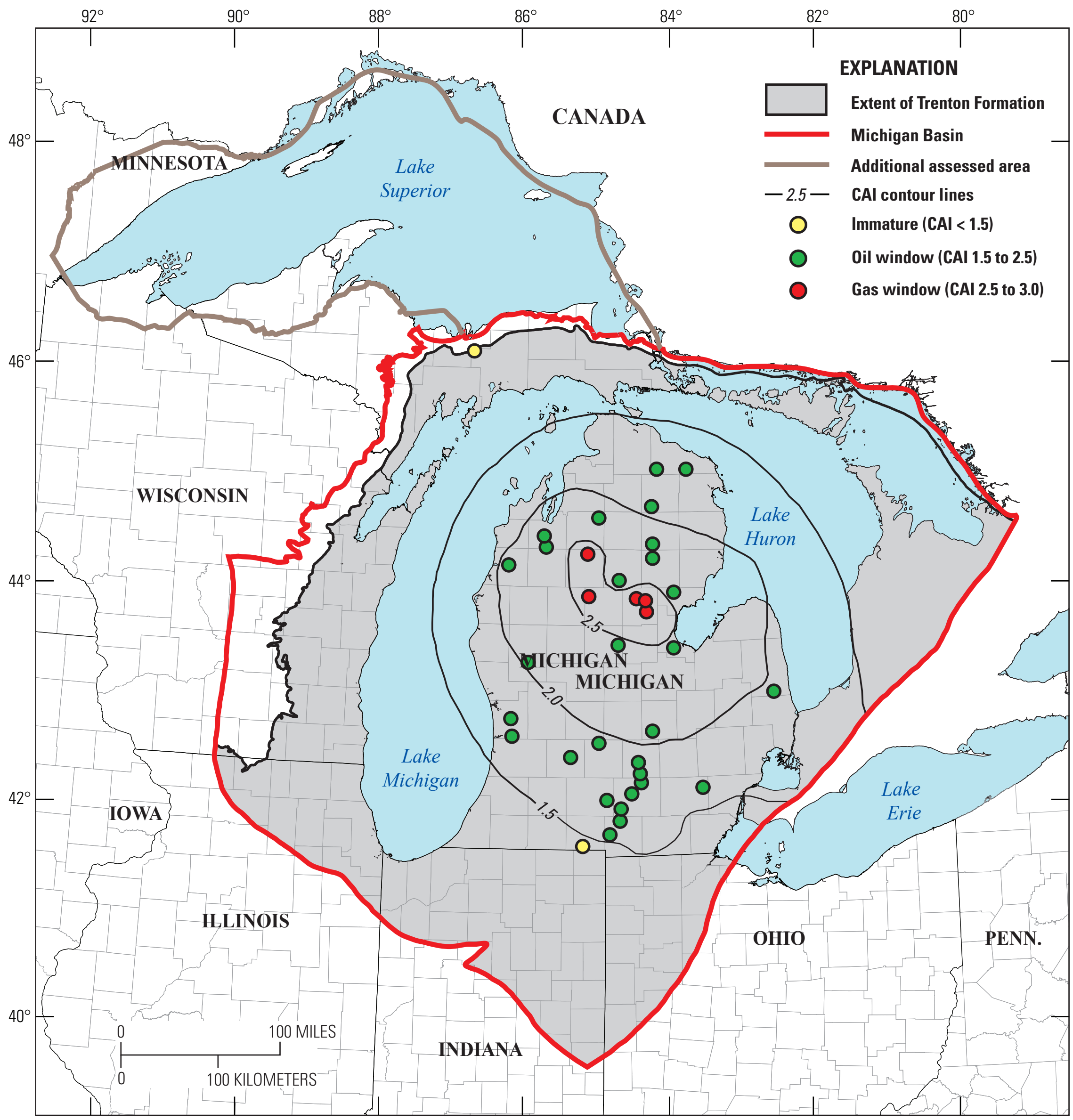
in turn, is overlain by the Collingwood Shale, the Point Pleasant Formation (which is stratigraphically equivalent to the Collingwood Shale), and (or) the Utica Shale (see cross sections in Wylie and others, 2004). In the Michigan Basin, the base of the Trenton Formation is delineated by two gamma-ray markers, which may be metabentonites. In central and northern Michigan, the top of the Trenton Formation is gradational with the base of the Collingwood Shale. In southern Michigan, however, the top of the Trenton Formation is a very sharp contact beneath the Utica Shale.

The Black River Formation ranges in thickness from about 100 to 500 ft in the Michigan Basin (Catacosinos and others, 1990). This unit is a brown to gray carbonate mudstone, with some beds of pelletal grainstone, chert, and volcanic ash (Hiatt and Nordeng, 1985; Keith, 1985a; Wilson and Sengupta, 1985; Catacosinos and others, 1990; Hurley and Budros, 1990). In places, the Black River Formation is greatly bioturbated. Within the lower part of the Black River Formation, there is a 20-ft-thick bed of laminated to cross-bedded dolomite. This bed is called the "Van Wert zone," and in cored intervals, it has porosity values of three to five percent and permeability values of about 10 md. The Van Wert zone is overlain and underlain by intensely burrowed carbonate mudstone and wackestone. Several geological cross sections through the Trenton Formation and Black River Formation interval are shown in Keith (1985a).

The Trenton Formation, which lies above the Black River Formation, ranges in thickness from about 150 to 500 ft in the Michigan Basin (Catacosinos and others, 1990). The Trenton Formation is a brown to gray, mottled, fossiliferous carbonate mudstone to packstone (Hiatt and Nordeng, 1985; Keith, 1985a; Wilson and Sengupta, 1985; Catacosinos and others, 1990; Hurley and Budros, 1990). In the lower part of the Trenton Formation, in eastern Michigan, the carbonates are interbedded with shales, and the Trenton Formation is dolomitized in places. In central and northern Michigan, however, the lower part of the Trenton Formation consists primarily of skeletal wackestone and minor packstone. The upper part of the Trenton Formation in the central part of the basin is dark, organic-rich, and argillaceous and has a restricted fauna of brachiopods and trilobites. In the western and southern parts of the Michigan Basin, the uppermost 20 to 50 ft of the Trenton Formation consists of ferroan dolomite (fig. 37) that is capped by an unconformity. In contrast, in the northeast and eastern parts of the Michigan Basin, where the Collingwood Shale intervenes between the upper part of the Trenton Formation and the typical Utica Shale, the upper part of the Trenton Formation is shaly.

Faunal assemblages in the Trenton Formation consist primarily of marine brachiopods, crinoids, gastropods, bryozoans, and trilobites. In places, the formation is intensely bioturbated. In some areas, a crossbedded dolomitic grainstone is present above skeletal limestone. From southeast to northwest, the Trenton Formation shows three distinct facies changes: (1) In the southeast part of the Michigan Basin and on the northwest flank of the Findlay arch, the Trenton Formation consists of brown, bioclastic wackestone and packstone with brachiopods and crinoids. (2) In the northwest part of the Michigan Basin, the Trenton Formation is more argillaceous, contains more organic-rich strata and also some thin, persistent shale beds throughout both the Trenton and Black River Formations. These shale beds range from 0.2 to 6 in. thick and contain organic material of source-rock quality. Some of these shale beds have been referred to as bentonites (DeHaas and Jones, 1984; Wilson and Sengupta, 1985; Harrison and Bohjanen, 1986), but Hurley and Budros (1990) have suggested that the shale beds may be of marine origin rather than bentonites. (3) In the Albion-Scipio area of southern Michigan, the Trenton Formation typically consists of carbonate mudstone, crinoid wackestone, and crinoid packstone. In this area, the upper 40 ft of the Trenton Formation is a finely crystalline, nonporous, ferroan dolomite of regional extent (called the "cap dolomite").

Several studies have identified three types of dolomite in the Trenton Formation (Keith, 1985a; Wilson and Sengupta, 1985; Middleton and others, 1993): (1) regional dolomite, which is predominant in the southern and western parts of the Michigan Basin and decreases in thickness from the Michigan Basin to the Illinois Basin; (2) ferroan-cap dolomite, which is present in all parts of the basin except the eastern part; and (3) fracture-related dolomite (in many places, this is saddle dolomite), which is present in fractures, vugs, and veins throughout the basin. The regional dolomite is thought to have formed from the mixing of meteoric water and sea water during early diagenesis (Budai and Wilson, 1991). The ferroan-cap dolomite is thought to have formed from compactional dewatering during burial diagenesis of shale overlying the Trenton Formation. The fracture-related dolomite is thought to have formed from hydrothermal solutions, and it overprints



The base map for this figure is from Nicholson and others (2004).

Figure 35. Map showing the thermal maturity of organic matter in the Middle Ordovician Trenton Formation and Collingwood Shale in the central part of the Michigan Basin based on conodont color alteration index (CAI). The CAI contours are based on limited data. With respect to petroleum generation, CAI <1.5 = immature, CAI from 1.5 to 2.5 = oil window, and CAI from 2.5 to 3.0 = gas window.

The base map for this figure is from Nicholson and others (2004).

Figure 36. Map of isopachs of the Middle Ordovician Trenton Formation and Black River Formation in the central part of the Michigan Basin (modified from Catacosinos and others, 1990).

The base map for this figure is from Nicholson and others (2004).

Figure 37. Map of the percentage of dolomite in the upper 50 feet of the Middle Ordovician Trenton Formation (modified from Prouty, 1988; Hurley and Budros, 1990; Keith and Wickstrom, 1992).

the ferroan-cap dolomite. Cross-cutting relations and isotopic studies also indicate that the fracture-related dolomite is younger than the ferroan-cap dolomite.

In the Albion-Scipio trend area (figs. 1 and 39), the Trenton Formation contains several late-stage, pore-filling minerals including anhydrite, calcite, pyrite, and trace amounts of fluorite, sphalerite, and barite (Wilson and Sengupta, 1985). According to Middleton and others (1993), solid petroleum (bitumen) coats saddle-dolomite cement and more rarely anhydrite, suggesting that the late-stage, diagenetic-mineral phases were associated with petroleum migration (a conclusion also reached by Budai and Wilson, 1991). Furthermore, the abundance of dolomite and various secondary minerals increases with depth, suggesting that the mineralizing fluids ascended from depth (Prouty, 1988).

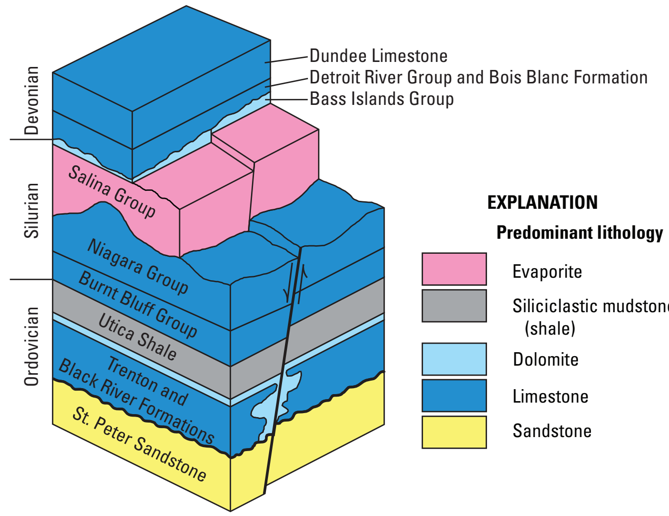


Figure 38. Block diagram of the Albion-Scipio field showing fractures and dolomitization in the Middle Ordovician Trenton Formation and also younger carbonate strata (Hurley and Budros, 1990).

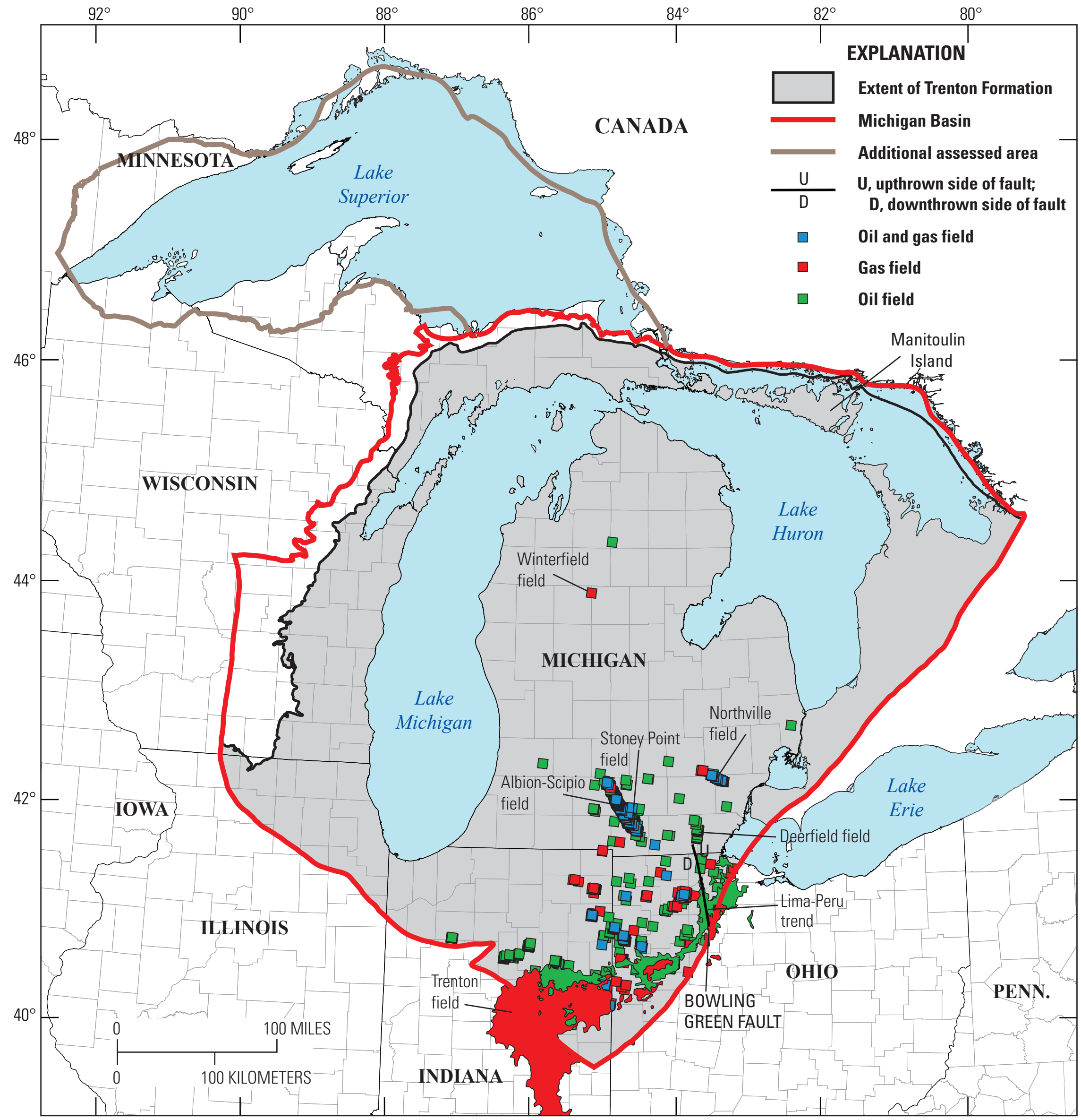
Assessment Unit Model

The Ordovician Trenton/Black River AU contains conventional petroleum accumulations. Petroleum generation in the Trenton Formation began during the Late Devonian (coincident with the Acadian orogeny) when the Collingwood Shale and thin shale beds in the upper part of the Trenton Formation entered the oil window in the deepest part of the basin (Hayba, 2005). Subsequently, during the Pennsylvanian and Permian (coincident with the Alleghanian orogeny), most of the Collingwood Shale and shale beds in the upper part of the Trenton Formation entered the gas window and continued to generate petroleum.

According to Prouty (1988), replacement dolomite, saddle dolomite (baroque dolomite), and petroleum occur in all of the major carbonate reservoirs of the Michigan Basin (Middle Ordovician Trenton and Black River Formations and Devonian Detroit River Group and Dundee and Traverse/Squaw Bay Limestones). At least some of the dolomite occurs in breccias that are thought to have formed by a reaction between carbonate rocks and petroleum-bearing hydrothermal brines (Tedesco, 1994). This reaction results in a conversion of dense carbonate strata to porous dolomite, an overpressured CO_2-rich gas phase, fracturing of local country rock due to increased pressures, and the formation of hydrogen sulfide and sulfide minerals. Studies by Hurley and Budros (1990) also support the model of dolomitizing fluids moving upward from depth rather than downward from the surface (fig. 38). Furthermore, during dolomitization, thin shale beds appear to have been local permeability barriers to vertical flow. As a result, in the Trenton and Black River Formations, dolomite zones have developed preferentially beneath extensive shale beds. Hurley and Budros (1990) also note that a liquid-petroleum phase is present in fluid inclusions in some dolomites, suggesting that petroleum was present during cement precipitation.

Dolomitization of strata in the Trenton and Black River Formations appears to have occurred throughout much of the Michigan Basin and also in the adjacent Appalachian Basin. Coniglio (1989), for example, notes that fracture-related dolomitization occurred on a basinwide scale in Michigan, from the Albion-Scipio field in the south to Manitoulin Island (fig. 39) in the north, and he notes that minor quantities of oil are present in discontinuous dolomite lenses within Ordovician strata on Manitoulin Island (Bailey and Cochrane, 1984). In the Appalachian Basin, hydrothermal-dolomite reservoirs have been identified and described in the Trenton and Black River Formations in Ontario, New York, and Ohio (Trevail and others, 2004; Sagan and Hart, 2006; Smith, 2006).

There is ongoing debate about the timing of dolomitization and petroleum migration. Much of the evidence cited by Prouty (1988) suggests that the petroleum migration route was upward along faults, and he postulates that petroleum entrapment occurred during the Early Mississippian. Middleton and others (1993), however, postulate that the movement of the fluids that caused the fracture-related dolomitization may be associated with the Pennsylvanian and Permian Alleghanian orogeny. A Permian age for petroleum migration is also supported by data from the Stoney Point field, where the Trenton and Black River Formations exhibit strong magnetic signatures consisting of a modern geomagnetic-field direction and a Late Permian geomagnetic-field direction (Suk and others, 1993). Subsequent work by Hayba (2005, 2006) indicates that the heat flux in the southeastern portion of the Michigan Basin was anomalously high during the time of maximum burial (Pennsylvanian and Permian), and this anomalous heat flux is attributed to topographically driven fluid migration from the Appalachian Basin, across the Findlay arch, and into the southeastern part of the Michigan Basin. As discussed by Rowan and others (2007), the evidence for westward fluid flow out of the Appalachian Basin during the Permian supports an Appalachian Basin provenance for Ordovician oils found in Trenton Formation and Black River Formation reservoirs on Findlay arch.



The base map for this figure is from Nicholson and others (2004).

Figure 39. Map showing the locations of oil and gas fields where production is from reservoirs in the Middle Ordovician Trenton Formation and Black River Formation in the U.S. portion of the Michigan Basin (Keith and Wickstrom, 1992; U.S. Geological Survey Web site http://energy.cr.usgs.gov/oilgas/noga). Identified fields are discussed in the text.

Throughout much of the Michigan Basin, most of the reservoir traps in the Trenton and Black River Formations are stratigraphic traps located over reactivated basement faults (that is, a combination of stratigraphic and structural features). In addition, stratigraphic traps are present along the strike of truncated Cambrian and Ordovician beds where these beds wedge out against the Findlay arch in southeastern Michigan and southwestern Ontario (Cohee, 1947). The cap dolomite in the Trenton Formation and the overlying Utica Shale act as reservoir seals. In some reservoirs, however, tight, nondolomitized limestones in the Trenton and Black River Formations provide the seals. Low-porosity limestone of regional extent may also act as a lateral reservoir seal.

Reservoir Characteristics

Most reservoirs in the Trenton and Black River Formations in the Michigan Basin have produced both oil and gas (fig. 39). Furthermore, most of these reservoirs consist of fractured limestone with associated hydrothermal dolomitization (Keith, 2000). For Trenton and Black River Formations reservoirs in Michigan, studies by Hurley and Budros (1990) show that porosity is developed in areas of pervasive dolomitization above and near fracture zones related to subsurface faults. The dominant fracture trends are N.30°W. and east–west, and most of the fractures are near vertical (60° to 90° from horizontal). For major fracture sets, fractures are evenly spaced, with horizontal spacing on the order of 45 ft or less. Open, partially filled, and filled fractures are common in the dolomitized areas. The fracture-filling material is primarily saddle dolomite, although calcite and anhydrite are present locally. There is a sharp contrast between productive dolomite and the nonproductive, tight, regional limestone. The typical reservoir rock is a dense, gray-brown dolomite with intercrystalline, vuggy, and (or) fracture porosity. In some intervals, vugs, fractures, and even caverns are extremely abundant. Most vugs or fractures are lined or filled with white saddle dolomite. Porosity histograms show that most of the samples have porosities of 2 to 5 percent. Porosity values of 8 to 12 percent are present, but uncommon. Matrix permeabilities range from 0.01 to 8,000 md, but most permeabilities are relatively low (less than 10 md). There is no uniform relation between porosity and permeability in the reservoirs. Bahr and others (1994) provide a chart that shows pressure versus depth for the Trenton Formation.

Along the Lima-Peru trend in Ohio and Indiana, the large Trenton field (fig. 39) is formed by the updip pinchout of the porous regional dolomite in the Trenton Formation southward into the ferroan-cap dolomite, low-porosity limestone, and argillaceous limestone (Keith, 1985a). Not all porosity in the Trenton field, however, is oil productive, because there are some porous areas that were water productive. Many of the oil reservoirs in the Trenton Formation along the Lima-Peru trend consist of dolomitized rocks associated with structural features (Keith, 1985a, 1988). In fact, throughout most of northern Indiana, all of the small fields that have production from the Trenton Formation are found on small structural features. The structural features are either normal faults or linear-fracture zones that may be related to faults. In some fields, the linear-fracture zones are associated with local synclinal features that coincide with areas of greater dolomitization. North of the Lima-Peru trend, some porosity with very poor lateral continuity is localized on small, "positive relief" structural features (Keith, 1985b, 1988). Where the Bowling Green fault zone cuts across the Lima-Peru trend in Ohio (fig. 39), reservoirs have formed by localized dissolution along fractures.

As with the Trenton and Black River Formation reservoirs in Michigan, the reservoirs in Ontario have been dolomitized and fractured adjacent to vertical faults (Middleton and others, 1993; Carter and Trevail, 2000). The reservoirs in Ontario are generally linear and may reach as much as 1.2 mi in length and 600 ft in width, often with several isolated pods of production. Furthermore, the reservoirs are commonly located at intersecting fracture systems, specifically on the down-dropped sides of fault blocks. In addition, there is usually vertical displacement of the underlying Precambrian basement surface, a structural depression over the dolomitized zone, and a change in character on seismic records within the dolomitized zone. These reservoirs in Ontario are laterally bounded by nonporous limestones and are overlain and sealed by gray marine shale of the Blue Mountain Formation (equivalent to the Utica Shale).

In the Michigan Basin, most of the known Trenton and Black River Formations reservoirs are located in the southeastern portion of the basin and along the Kankakee and Findlay arches. These reservoirs (described in the following paragraphs) include the Albion-Scipio field, the Stoney Point field, the Deerfield field, the Northville field, and the Lima-Peru trend (fig. 39). Some geochemical studies and fluid-flow models have suggested that the primary source rocks for the petroleum in the fields on the Kankakee and Findlay arches may be located to the east in the Appalachian Basin rather than the Michigan Basin to the north and west (Hayba, 2006; Rowan and others, 2007, 2008).

The Albion-Scipio field is predominantly an oil reservoir that is an amalgamation of several fields and reservoir compartments along a northwest trend in Jackson, Calhoun, and Hillsdale Counties in Michigan (Beghini and Conroy, 1966; Keith, 1988; Catacosinos and others, 1990; Hurley and Budros, 1990). The Scipio field was discovered in 1957, and the Albion field was discovered in 1958. The combined Albion-Scipio trend is about 31 mi long, a maximum width of about 1 mi, and covers a total area of approximately 14,500 acres. The field is a synclinal structure that is attributed to left-lateral strike-slip movement on a reactivated northwest-trending basement fault. The reservoir is constrained to a relatively narrow interval of porous, brecciated dolomite surrounded by dense limestone that does not contain oil. Reservoir-pore types include fracture porosity, vugs (cavernous, in places), and intercrystalline porosity. Dolomite and enhanced porosity are developed near fracture zones and beneath shale beds. In most wells, the cap dolomite in the Trenton Formation and the overlying Utica Shale act as reservoir seals. In the Albion-Scipio field, the average depth to pay is about 4,000 ft, and the average pay thickness is 50 to 60 ft. The gross reservoir is about 600 ft thick, the oil column is typically 150 to 200 ft thick, and there is a gas cap that ranges from 50 to 400 ft thick. Most of the Albion-Scipio field initially had a free gas cap with a 150- to 200-ft-thick oil column. During development of the field, zones of lost circulation (caused by fractures, vugs, and caverns) were encountered frequently. Drilling was allowed on 20-acre spacing, and the original reservoir-drive mechanisms were solution-gas drive, gas-cap expansion, gravity drainage, and limited water drive. The cumulative recovery through January 1, 1987, was 124 MMBO.

The Stoney Point field (Jackson and Hillsdale Counties, Michigan) is very similar to the Albion-Scipio field. The Stoney Point field is predominantly an oil reservoir along a northwest trend in Jackson and Hillsdale Counties, Michigan (Anonymous, 1984; Catacosinos and others, 1990; Hurley and Budros, 1990). The Stoney Point field was discovered in 1983 and covers a total area of about 2,900 acres. As with the Albion-Scipio field, the Stoney Point field is a synclinal structure that is attributed to left-lateral strike-slip movement on a reactivated northwest-trending basement fault. The reservoir is a relatively narrow interval of porous, brecciated dolomite surrounded by dense limestone that does not contain oil. Reservoir-pore types include fracture porosity, vugs (cavernous, in places), and intercrystalline porosity. Dolomite and porosity are developed near fracture zones and beneath shale beds. In most wells, the cap dolomite in the Trenton Formation and the overlying Utica Shale act as reservoir seals. In the Stoney Point field, the maximum thickness of the oil column is 210 ft, and a gas cap is present. Most of the Stoney Point field initially had a free gas cap with a 150- to 210-ft-thick oil column. During development of the field, zones of lost circulation (caused by fractures, vugs, and caverns) were encountered frequently. Drilling was allowed on 40-acre spacing, and the original reservoir-drive mechanisms were primarily gas-cap expansion and gravity drainage, although a water-drive mechanism became more important later in the field life. The cumulative recovery through January 1, 1987, was 3.6 MMBO, and by 2004 the cumulative production was closer to 10 MMBO (W.B. Harrison, III, written commun., 2004).

The Deerfield field (Monroe County, Michigan) is predominantly an oil reservoir (with some gas) that is located along a normal fault associated with the Lucas-Monroe monocline, which is a northwest extension of the Bowling Green fault zone in Ohio (Cohee, 1947, 1948; Cohee and Landes, 1958; Ives, 1960a,b; Keith, 1988; Hurley and Budros, 1990). The field was discovered in 1920; the reservoir interval consists of lenses of dolomite surrounded by low-porosity limestone. The primary producing interval is within the upper 50 ft of the Trenton Formation, but production has also been established in the Trenton and Black River Formations as much as 550 ft below the top of the Trenton Formation. The average reservoir pay is 10 ft thick. Salt water is not produced with the oil, and the reservoir-drive mechanism is gas-expansion.

The Northville field (Washtenaw, Oakland, and Wayne Counties, Michigan) is located on a northwest-trending anticlinal structure associated with the Howell anticline (Ives, 1960a,b; Prouty, 1988; Hurley and Budros, 1990; Budai and Wilson, 1991). Production from this field began from the Silurian Salina and Niagara Groups in 1937, from the Devonian Dundee Limestone in 1948, and from the Trenton and Black River Formations in 1954. Production from the Trenton and Black River Formations consists of both oil and gas. Trenton and Black River Formations production is from fractured and dolomitized limestone on the east flank of the anticlinal structure. The fractures are lined with dolomite cement and also contain barite “intergrown” with calcite. In this field, the depth to the Trenton Formation is about 4,300 ft, and the net pay thickness of Trenton reservoirs is 40 ft.

The Lima-Peru trend (Ohio and Indiana) is a trend of oil and gas fields along the Findlay, Kankakee, and Cincinnati arches (Cohee, 1947; Cohee and Landes, 1958; Keith, 1985a, 1988; Caprarotta and others, 1988; Wickstrom and Gray, 1988; Hurley and Budros, 1990; Keith, 1991). The fields in this trend are the subject of the very first USGS publication on petroleum (Orton, 1889). Production from fields along this trend began in 1884 and reached a peak in 1896. Wickstrom and Keith (1997) estimate that the fields along this trend have produced about 500 MMBO and 1 TCFG from the Trenton Formation. Along the Lima-Peru trend, oil reservoirs are more abundant on the northern side of the Kankakee arch and the western side of the Cincinnati and Findlay arches, whereas gas reservoirs are more abundant to the south and east of the oil reservoirs (fig. 39). Most production is from the upper 197 ft of the Trenton Formation, although some oil is produced from the underlying Black River Formation. Most petroleum reservoirs along the Lima-Peru trend are in porous dolomite, but not all porous intervals are productive. Along the Bowling Green fault zone (fig. 39), which is also part of the Lima-Peru trend, dolomite and petroleum are present throughout the entire Trenton and Black River Formations interval, but most individual pay zones are less than 16 ft thick and are very discontinuous both laterally and vertically. Within the reservoir intervals along the Bowling Green fault zone, porosity types include small interparticle porosity and intercrystalline porosity, as well as large isolated vugs.

Although most of the known Trenton and Black River Formations fields are located in the southeastern portion of the basin, some production from the Trenton Formation has been established in the northern portion of the Michigan Basin. For example, gas was produced from the Trenton Formation and Black River Formation interval at one well in the Winterfield field (fig. 39). A second example is that oil was produced from the Trenton Formation on Manitoulin Island (fig. 39) from 1905 to 1940 (Cohee, 1948). At this location, the depth to the top of the Trenton Formation ranged from 115 to 517 ft, and the producing zone was about 12 to 20 ft below the top of the Trenton Formation. These wells on Manitoulin Island, however, apparently produced too much water to be economically viable.

Petroleum Geochemistry

A whole-oil gas chromatogram for oil collected from a well producing from the Trenton Formation in the Albion-Scipio field in Calhoun County, Michigan, is shown in figure 40 (chromatogram modified from Rullkötter and others, 1986, their fig. 4). The hydrocarbon distribution is characterized by an odd-carbon predominance in the n-C_9 to n-C_{20} alkanes and relatively low amounts of isocyclic compounds including pristane and phytane. The odd-carbon preference index (CPI, modified from Bray and Evans, 1961) between n-C_{12} and n-C_{20} is 1.29, the pristane/phytane ratio is approximately 2, and the pristane/n-C_{17} ratio is 0.08 (all values are from measurements of peak height). The hydrocarbon distribution shown for this oil is dominated by the geochemical signature of *Gloeocapsamorpha prisca* (an organic-walled microfossil of Cambrian and Ordovician age) (Jacobson and others, 1988) and is also similar to hydrocarbon distributions for other oils from the Trenton Formation illustrated in Illich and Grizzle (1983, 1985), Powell and others (1984), and Hurley and Budros (1990).

The chemical compositions (N_2 mole percent, CO_2 mole percent, H_2S mole percent, ethane/isobutane mole percent/mole percent, and gas wetness percent) of 80 natural gas samples collected from wells producing from the Trenton Formation (79 samples) and Black River Formation (1 sample) are summarized in table 2. These samples are from Calhoun, Hillsdale, Jackson, and Lenawee Counties in south-central Michigan where reservoir depths range from 3,500 to 4,850 ft, increasing in depth from south to north (fig. 41). The data summarized in table 2 are from Moore and Sigler (1987), Hamak and Sigler (1991), and the data set, Michigan Oil and Gas Well Gas Analyses Data from the Michigan Geological Repository for Research and Education at Western Michigan University (http://wsh060.westhills.wmich.edu/MGRRE/data/). The data in the geographic distribution plots shown in figures 42, 43, and 44 are also from these data sets.

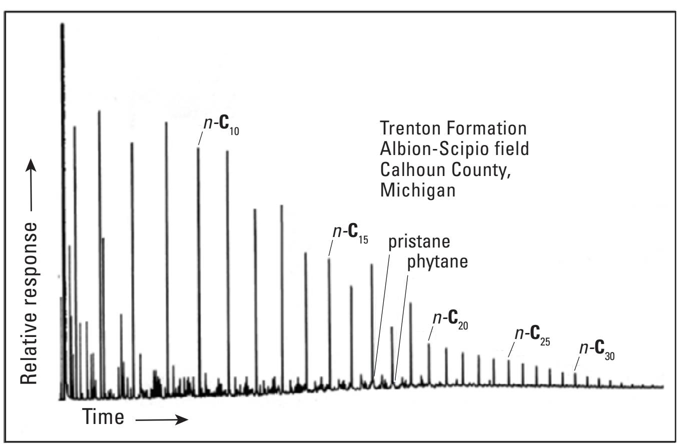


Figure 40. Saturated-hydrocarbon gas chromatogram for oil collected from a well producing from a reservoir in the Middle Ordovician Trenton Formation (Albion-Scipio field) in Calhoun County, Michigan (modified from Rullkötter and others, 1986, their figure 4).

These 80 natural gases are characterized by very low H_2S contents (median <0.01 mole percent), very low CO_2 contents (median = 0.01 mole percent), very high N_2 contents (median = 18 mole percent), and an intermediate ethane/isobutane ratio (median = 18). The geographic distribution of CO_2 contents for the 80 samples is shown in figure 42; N_2 contents, figure 43; and ethane/isobutane ratios, figure 44. For these samples, the measured chemical variables show no consistent patterns relative to geographic distribution or to reservoir depth.

Petroleum Resources

In the 2004 assessment of the U.S. portion of the Michigan Basin, the USGS assessed the Ordovician Trenton/Black River AU as a conventional petroleum accumulation. The assessment unit was considered to be primarily oil-prone, but the undiscovered fields were estimated to include both oil and gas fields. For the oil fields, the estimated volumes of undiscovered, technically recoverable oil resources are 179 MMBO at the 95-percent certainty level, 671 MMBO at the 50-percent certainty level, 1.43 billion barrels of oil (BBO) at the 5-percent certainty level, and a mean of 724 MMBO. For associated natural gas, the estimated volumes are 333 BCGF at the 95-percent certainty level, 1.31 TCFG at the 50-percent certainty level, 3.04 TCFG at the 5-percent certainty level, and a mean of 1.45 TCFG. For associated natural gas liquids, the estimated volumes are 22.0 MMBNGL at the 95-percent certainty level, 88.5 MMBNGL at the 50-percent certainty level, 224 MMBNGL at the 5-percent certainty level, and a mean of 101 MMBNGL (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).

For the gas fields, the estimated volumes of undiscovered, technically recoverable natural gas resources are 122 BCGF at the 95-percent certainty level, 502 BCFG at the 50-percent certainty level, 1.17 TCFG at the 5-percent certainty level, and a mean of 557 BCFG. For natural gas liquids, the estimated volumes are 2.3 MMBNGL at the 95-percent certainty level, 9.7 MMBNGL at the 50-percent certainty level, 24.8 MMBNGL at the 5-percent certainty level, and a mean of 11.2 MMBNGL (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).

For the assessment calculations, a minimum grown field size of 0.5 MMBO equivalent was used for oil fields, and a minimum grown field size of 3 BCFG was used for gas fields. As of 2004, the Ordovician Trenton/Black River AU contained five known oil fields and one known gas field with grown field sizes exceeding the minimum field sizes. Also as of 2004, the assessment unit was estimated to have produced a cumulative of 138 MMBO and 275 BCFG in the State of Michigan (figs. 9 and 10). The numbers of undiscovered accumulations greater than the minimum grown field size were estimated as

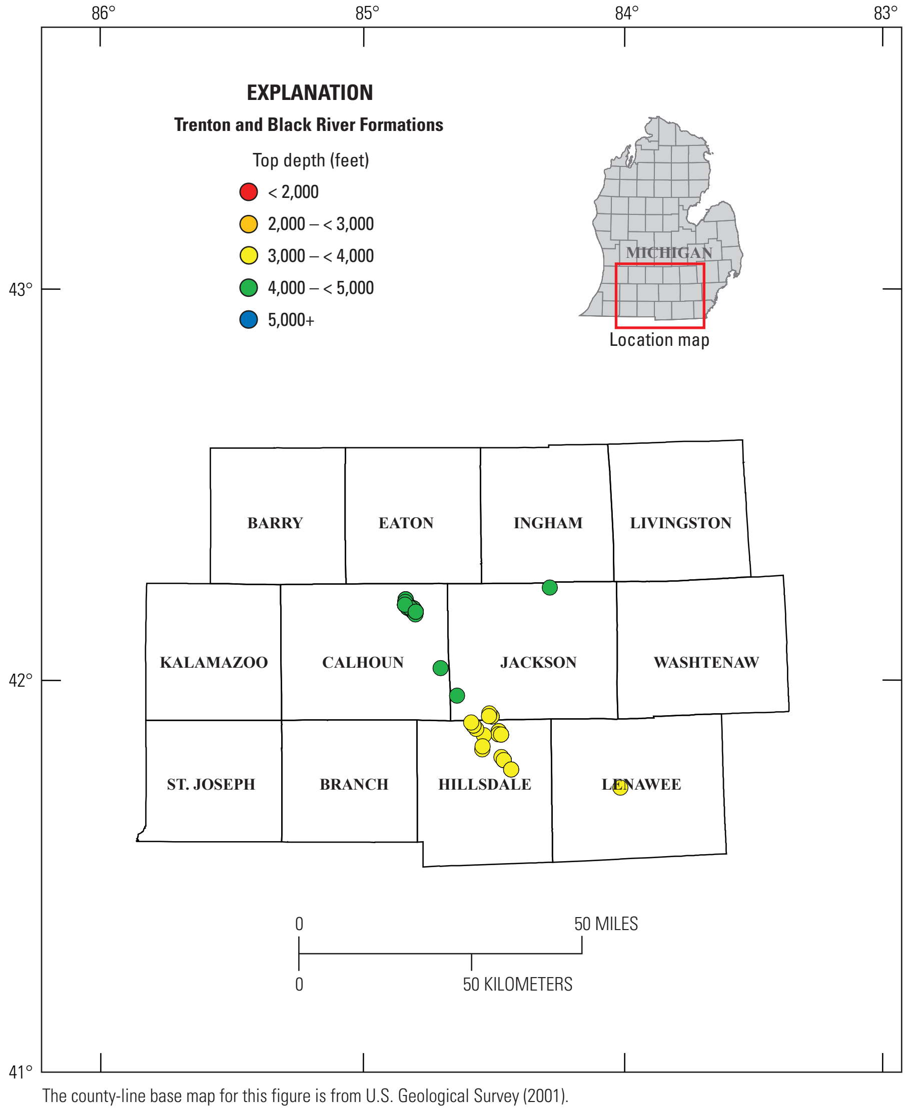
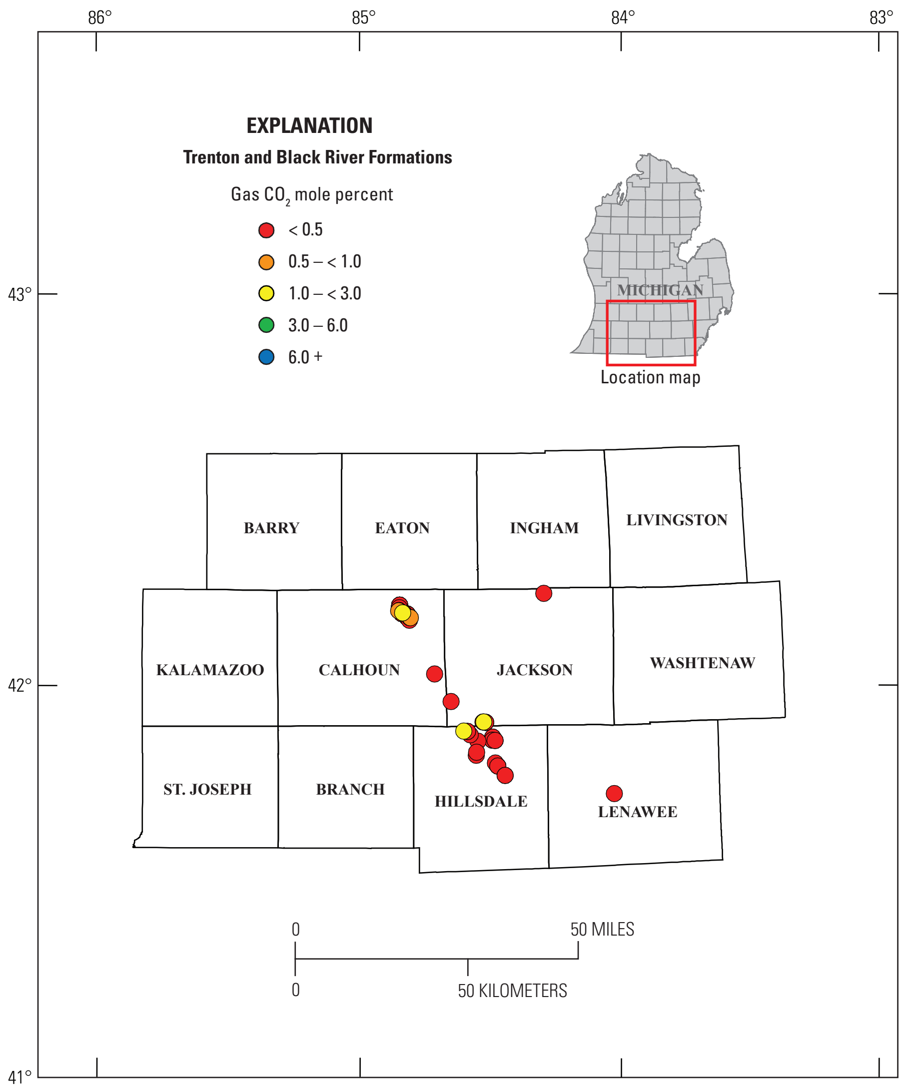


Figure 41. Map showing depths (in feet) from the surface to reservoirs from which natural gas samples were collected from the Middle Ordovician Trenton Formation in south-central Michigan.

Table 2. Statistical summary of the chemical compositions of 80 natural gas samples collected from wells producing from the Middle Ordovician Trenton and Black River Formations in Calhoun, Hillsdale, Jackson and Lenawee Counties in south-central Michigan.

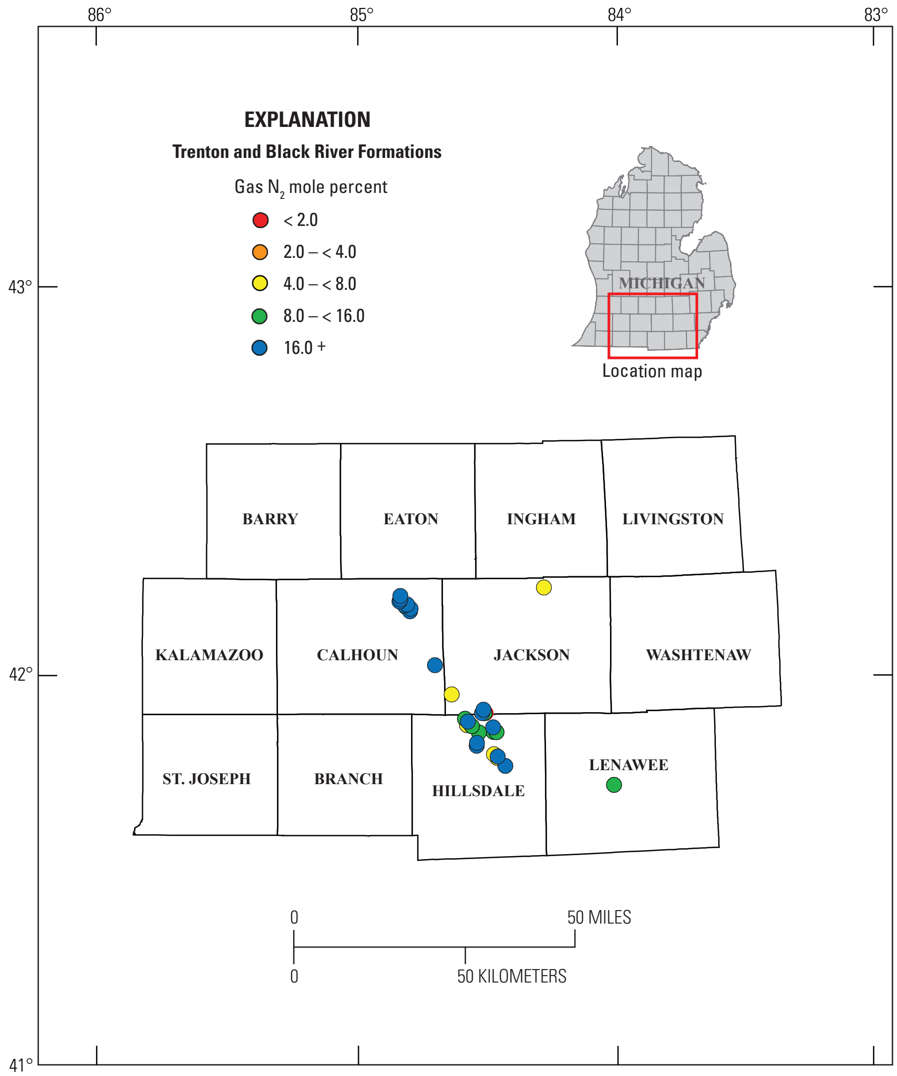
[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	80	80	80	79	80
Median	18	0.01	<0.01	18	20
Average, Standard deviation	18 ± 6.3	0.14 ± 0.35	<0.01 ± <0.01	17 ± 4.2	23 ± 9.4
Range	1.9–37	<0.01–2.6	<0.01–0.01	5.0–25	5.6–45



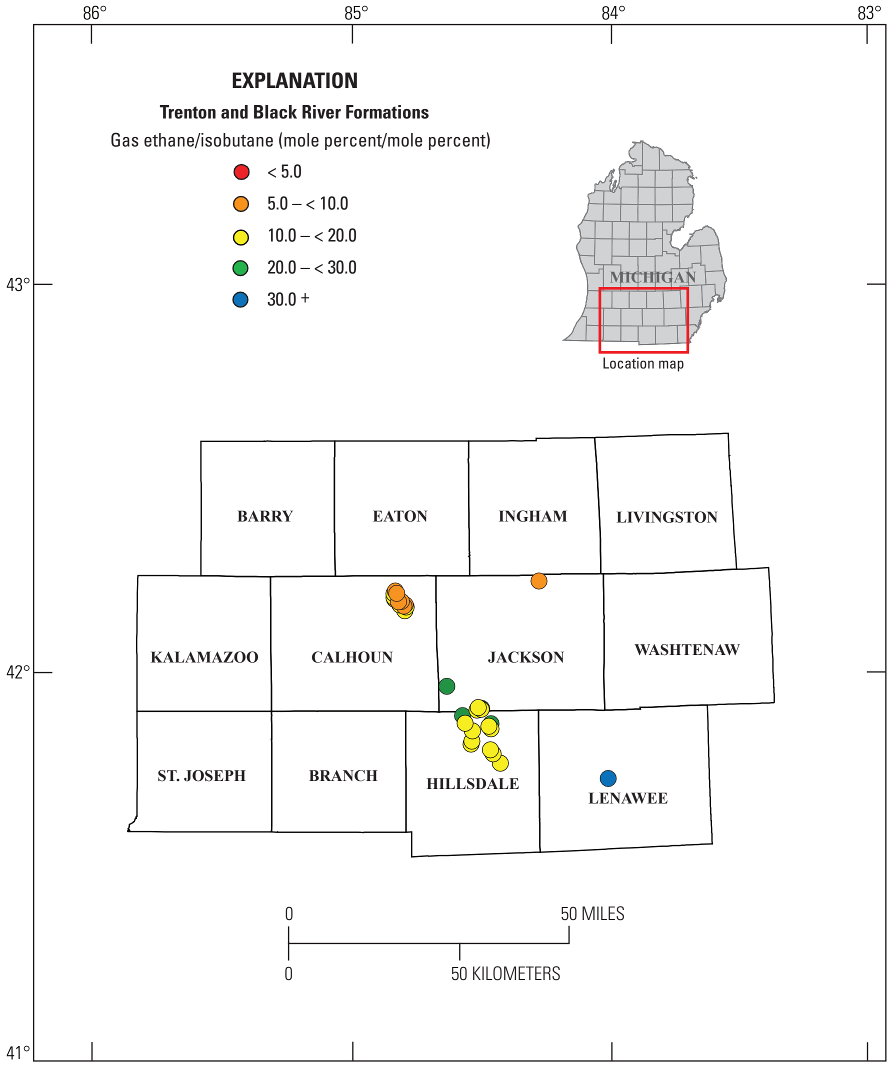
The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 42. Map showing the geographic distribution of carbon dioxide (CO_2) contents (mole percent) of 80 natural gas samples collected from wells producing from the Middle Ordovician Trenton Formation and Black River Formation in south-central Michigan.



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 43. Map showing the geographic distribution of nitrogen (N_2) contents (mole percent) of 80 natural gas samples collected from wells producing from the Middle Ordovician Trenton and Black River Formations in south-central Michigan.



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 44. Map showing the geographic distribution of ethane/isobutane (mole percent/mole percent) of 80 natural gas samples collected from wells producing from the Middle Ordovician Trenton and Black River Formations in south-central Michigan.

follows: minimum = 1 oil accumulation and 1 gas accumulation, mode = 60 oil accumulations and 10 gas accumulations, and maximum = 200 oil accumulations and 40 gas accumulations. The sizes of undiscovered accumulations greater than the minimum grown field size were estimated as follows: minimum = 0.5 MMBO and 3 BCFG, median = 3 MMBO and 18 BCFG, and maximum = 300 MMBO and 600 BCFG.

Ordovician Collingwood Shale Continuous Gas Assessment Unit

The Middle Ordovician Collingwood Shale is the only stratigraphic unit in the Ordovician Collingwood Shale Continuous Gas AU. The thickness of the Collingwood Shale ranges from 0 to about 36 ft, and the unit is present only in the northern part of the basin (fig. 32). The Collingwood Shale is found in outcrop in Ontario, Canada, and the elevation of the base of the Collingwood Shale ranges from about 500 ft above sea level on the margins of the basin to 10,000 ft below sea level in central Michigan (fig. 33).

The Collingwood Shale rests conformably on the Trenton Formation and is overlain by gray to dark-gray Utica Shale (fig. 31) (Hiatt and Nordeng, 1985; Catacosinos and others, 1990). Where the Collingwood Shale is absent, the Utica Shale rests directly on the underlying Trenton Formation, but the contact may not be conformable. In Ohio, strata that are equivalent to the Collingwood Shale are mapped as the Point Pleasant Formation.

The Collingwood Shale is a brown to black, laminated, calcareous shale and argillaceous limestone (micrite). The calcareous shale and argillaceous limestone are interbedded layers of fossil debris containing abundant pyrite and phosphate (Hiatt and Nordeng, 1985; Catacosinos and others, 1990). The argillaceous limestone (micrite) contains sparse fragments of brachiopods, ostracodes, and trilobites; graptolites are present on bedding planes. The top of the Collingwood Shale is described as a "weathered zone." According to Russell and Telford (1984), organic-carbon contents in the Collingwood Shale are typically 6 to 8 weight percent, but in places the organic-carbon content is up to 12 weight percent.

Assessment Unit Model

The Ordovician Collingwood Shale Continuous Gas AU contains a continuous (or "unconventional") petroleum accumulation. The Collingwood Shale is both the source rock for the petroleum and the reservoir rock. Petroleum generation began to occur during the Late Devonian (coincident with the Acadian orogeny) when the Collingwood Shale entered the oil window in the deepest part of the basin (Hayba, 2005). Subsequently, during the Pennsylvanian and Permian (coincident with the Alleghanian orogeny), most of the Collingwood Shale in the deepest part of the basin entered the gas window and continued to generate petroleum. With respect to petroleum generation, organic-rich shales in the Collingwood Shale are within the gas-generation window in the deepest part of the Michigan Basin and within the oil-generation window on the margins of the basin (fig. 35). Petroleum in the Ordovician Collingwood Shale Continuous Gas AU is thought to be primarily gas trapped in fractures and adsorbed within the shale. Both the Collingwood Shale and the overlying Utica Shale may act as reservoir seals to limit gas migration.

Reservoir Characteristics

As of 2004, petroleum had not been produced commercially from the Ordovician Collingwood Shale Continuous Gas AU, although shale within the assessment interval is a potential reservoir rock. If petroleum production were to be established, then it would likely consist of gas from the Collingwood Shale.

Undiscovered Petroleum Resources

For the 2005 assessment of undiscovered, technically recoverable oil and gas resources of the U.S. portion of the Michigan Basin, the USGS identified the Ordovician Collingwood Shale Continuous Gas AU but did not assess it quantitatively (Swezey and others, 2005, their table 1). At the time of the assessment, no petroleum production had been established from the assessment unit, and available stratigraphic and geochemical information were insufficient to conduct a quantitative assessment.

Silurian Burnt Bluff Assessment Unit

The Middle Silurian Burnt Bluff Group is the only stratigraphic unit in the Silurian Burnt Bluff AU. Thickness of the Burnt Bluff Group ranges from approximately 20 to 300 ft throughout most of the Michigan Basin (fig. 45), and elevations at the top of the Burnt Bluff Group range from about 2,000 to 8,500 ft below sea level (fig. 46). The Burnt Bluff Group overlies the Lower Silurian Cabot Head Shale (Cataract Group) and is overlain by the Middle Silurian Manistique Group. The contact with the overlying Manistique Group is gradational. The Burnt Bluff Group consists of dolomitic limestone in outcrop and is limestone in the subsurface (Harrison, 1985; Catacosinos and others, 1990, 2001)

Throughout much of its extent, the Burnt Bluff Group consists of the three formations (from base to top): The Lime Island Formation, the Byron Formation, and the Hendricks Formation (fig. 47). These three formations grade south into shaly carbonate that is called the Clinton Formation, which is generally less than 30 ft thick. The Lime Island Formation is a limestone that contains abundant brachiopods, as well as some trilobites, mollusks, corals, and echinoderms. Most of the fossils are a mixture of broken and abraded skeletal debris. The Byron Formation is a dolomitic limestone that includes laminated algal mats and massive beds of micrite, with mudcracks, vertical dewatering structures, and minor anhydrite.

The base map for this figure is from Nicholson and others (2004).

Figure 45. Map of isopachs of the Middle Silurian Burnt Bluff Group in the central part of the Michigan Basin (from Catacosinos and others, 1990).

The base map for this figure is from Nicholson and others (2004).

Figure 46. Structure map on top of the Middle Silurian Burnt Bluff Group and stratigraphically equivalent strata in the central part of the Michigan Basin (from Catacosinos and others, 1990). The Burnt Bluff Group grades southward into the Clinton Formation, a shaly carbonate (Catacosinos and others, 2001).

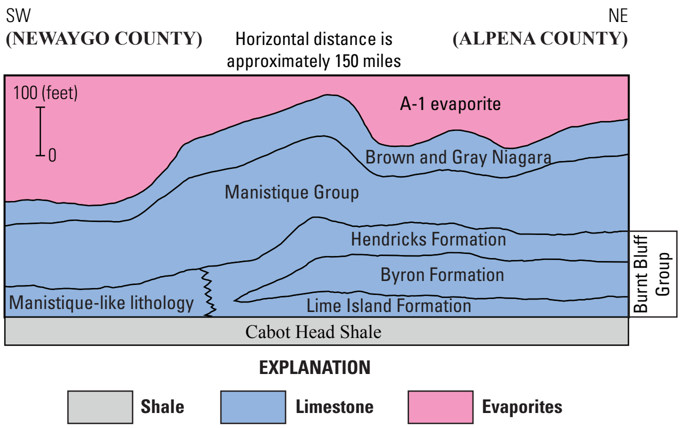


Figure 47. Cross section of Silurian strata in northern Michigan (from Harrison, 1985). Datum is the top of the Silurian Cabot Head Shale. Brown and Gray Niagara are informal units of the Niagara Group.

Megafossils are absent, although ostracode shells are relatively common. The Hendricks Formation is a limestone containing laminar and digitate stromatoporoids, colonial and solitary rugose corals, and colonial tabular corals. Some skeletal debris (gravel-sized and sand-sized) and micrite are present between the corals and stromatoporoids. These three formations of the Burnt Bluff Group grade basinward into irregularly bedded, nodular micritic limestone with a few beds of echinoderm debris (lithologically similar to the Manistique Group). Farther basinward (south), these strata grade into shaly carbonate.

Assessment Unit Model

The Silurian Burnt Bluff AU contains conventional petroleum accumulations. Initially, in this assessment, gas chemical analyses supported the hypothesis that source rocks for petroleum in Burnt Bluff Group reservoirs were the Collingwood Shale and shale beds in the upper part of the Trenton Formation. However, with the acquisition of additional gas chemical analyses, it was concluded that the source rocks for the petroleum in the Burnt Bluff Group reservoirs were more likely to be in the Foster Formation (the uppermost formation within the Prairie du Chien Group), the source rocks for petroleum in reservoirs in the Ordovician Sandstones and Carbonates AU. This uncertainty of the source rock for the natural gases in the Burnt Bluff Group may be resolved when chemical analyses of produced gases from the Collingwood Shale in central and northern Michigan become available.

Assuming that the Foster Formation is the source of the Burnt Bluff Group gas, petroleum generation and migration from the Foster Formation began during the Late Devonian (coincident with the Acadian orogeny) when the Foster Formation entered the oil window in the deepest part of the basin. Subsequently, during the Pennsylvanian and Permian (coincident with the Alleghanian orogeny), most of the Foster Formation entered the gas window and continued to generate petroleum. Today, the thermal maturity of organic matter in most of the Foster Formation is within the gas window. The Burnt Bluff Group reservoirs in the northeastern part of the assessment unit (fig. 48) are primarily stratigraphic traps consisting of reef complexes and reef-flank debris. The Burnt Bluff Group reservoirs in the southwestern part of the assessment unit (fig. 48) are stratigraphic traps in lenses of fractured dolomite surrounded by low-porosity limestone. The Burnt Bluff Group reservoirs primarily contain gas, which migrated upward along fractures from the underlying Foster Formation. Shale and carbonate mudstone act as reservoir seals.

Reservoir Characteristics

Most reservoirs in the Burnt Bluff Group have produced gas with traces of condensate. Examples of fields that produce from the Burnt Bluff Group include the Hershey-Evart field in Osceola County and the Fletcher Pond field in Alpena County (fig. 48). At the Hershey-Evart field, gas has been produced from the Mississippian informal Michigan stray sandstone since 1971 and from the underlying Burnt Bluff Group since 1982. The Burnt Bluff Group production is from fractured, nodular, dolomitic limestone with secondary porosity, which is surrounded by a dense and tight limestone (Bricker, 1983; Harrison, 1985; Catacosinos and others, 1990). At the Fletcher Pond field, which was discovered in 1984, most production is from shaly carbonate in the Burnt Bluff Group, although one well produces gas from a coral-stromatoporoid grainstone (Bricker and Henderson, 1985; Harrison, 1985; Catacosinos and others, 1990).

Petroleum Geochemistry

The chemical compositions (N_2 mole percent, CO_2 mole percent, H_2S mole percent, ethane/isobutane mole percent/mole percent, and gas wetness percent) for two distinct groups of natural gases produced from reservoirs in the Burnt Bluff Group are summarized in table 3 (nine gas samples) and table 4 (eight gas samples). The first group of samples (table 3) is from Osceola County, in west-central Michigan (Os in fig. 48), where reservoir depths range from 8,010 to 8,070 ft; median reservoir depth is 8,060 ft. The second group of samples (table 4) is from Alcona, Alpena, and Montmorency Counties in northeastern Michigan (Ac, Ap, and M in fig. 48), where reservoir depths range from 5,520 to 7,570 ft; median reservoir depth is 7,070 ft. The data summarized in tables 3 and 4 are from Moore and Sigler (1987), Hamak and Sigler (1991), and two data sets, Michigan Oil and Gas Well Gas Analyses Data and Michigan Public Service Commission MichCon "TIPS" Data from the Michigan Geological Repository for Research and Education at Western Michigan University (http://wsh060.westhills.wmich.edu/MGRRE/data/).

The base map for this figure is from Nicholson and others (2004).

Figure 48. Map showing the locations of oil and gas fields where production is from reservoirs in the Silurian Burnt Bluff Group in the U.S. portion of the Michigan Basin (from U.S. Geological Survey Web site http://energy.cr.usgs.gov/oilgas/noga). Identified fields are discussed in the text; Ac, Alcona County; Ap, Alpena County; M, Montmorency County; Os, Osceola County.

Table 3. Statistical summary of the chemical compositions of nine natural gas samples collected from wells producing from the Middle Silurian Burnt Bluff Group in Osceola County in west-central Michigan.

[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	9	9	9	9	9
Median	0.49	0.12	<0.01	250	2.7
Average, Standard deviation	0.74 ± 0.69	0.13 ± 0.05	<0.01 ± <0.01	250 ± 13	2.7 ± 0.2
Range	0.47–2.57	<0.01–0.23	<0.01–<0.01	236–274	2.5–2.7

Table 4. Statistical summary of the chemical compositions of eight natural gas samples collected from wells producing from the Middle Silurian Burnt Bluff Group primarily in Alcona, Alpena, and Montmorency Counties in northeastern Michigan.

[*Wetness (percent) = 100 × (1− [C_1 mole percent /ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	8	8	2	8	8
Median	3.2	0.02	0.05	6.9	15
Average, Standard deviation	3.6 ± 1.3	0.04 ± 0.07	0.05 ± 0.05	7.7 ± 2.9	15 ± 3.7
Range	1.7–5.7	<0.01–0.20	<0.01–0.1	5.1–13	7.7–19

As listed in tables 3 and 4, significant compositional differences exist between these two groups of gases including gas wetness percent, N_2 mole percent, and ethane/isobutane ratios. However, the compositional differences between these two groups are similar to the ranges of compositions of natural gases collected from reservoirs in the underlying Ordovician Sandstones and Carbonates AU. For example, gas wetness values of gases from Burnt Bluff Group reservoirs in Osceola County in west-central Michigan (table 3) are similar to wetness values of gases from St. Peter Sandstone reservoirs in Osceola and Missaukee Counties, Michigan (see fig. 30). Likewise, the gas wetness values for gases from Burnt Bluff Group reservoirs in Alcona, Alpena, and Montmorency Counties, in northeastern Michigan (table 4), are similar to the gas wetness values for gases from St. Peter Sandstone reservoirs in Oscoda, Ogemaw, and Crawford Counties, also in northeastern Michigan (see fig. 30).

Undiscovered Petroleum Resources

In the 2004 assessment of the U.S. portion of the Michigan Basin, the USGS assessed the Silurian Burnt Bluff AU as a conventional petroleum accumulation. The assessment unit was considered to be primarily gas-prone, and the undiscovered fields were estimated to include only gas fields. For these gas fields, the estimated volumes of undiscovered, technically recoverable natural gas resources within the Silurian Burnt Bluff AU are 43.8 BCGF at the 95-percent certainty level, 139 BCFG at the 50-percent certainty level, 286 BCFG at the 5-percent certainty level, and a mean of 149 BCFG. For natural gas liquids, the estimated volumes are 0.8 MMBNGL at the 95-percent certainty level, 2.7 MMBNGL at the 50-percent certainty level, 6.1 MMBNGL at the 5-percent certainty level, and a mean of 3.0 MMBNGL (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).

For the assessment calculations, a minimum field size of 3 BCFG was used for gas fields. As of 2004, the Silurian Burnt Bluff AU contained six known gas fields with grown field sizes exceeding the minimum size. Also as of 2004, the assessment unit was estimated to have produced a cumulative of 0.14 MMBO and 3 BCFG in the State of Michigan (figs. 9 and 10). The numbers of undiscovered accumulations greater than the minimum grown field size were estimated as follows: minimum = 1 gas accumulation, mode = 10 gas accumulations and maximum = 40 gas accumulations. The sizes of undiscovered accumulations greater than the minimum grown field size were estimated as follows: minimum = 3 BCFG, median = 8 BCFG, and maximum = 30 BCFG.

Silurian Niagara/Salina Total Petroleum System

The Silurian Niagara/Salina TPS includes identified petroleum source-rock intervals in the Middle Silurian Niagara Group and the overlying Upper Silurian Salina Group, and three petroleum assessment units: (1) Silurian Niagara AU, (2) Silurian A-1 Carbonate AU, and (3) Devonian Sylvania Sandstone AU (fig. 11). The Niagara Group overlays the Middle Silurian Manistique Group and is overlain by the Salina Group. The Salina Group, in turn, is overlain by the Upper Silurian Bass Islands Group (fig. 5).

Silurian Petroleum Source Rocks

In Ontario, Canada, on the eastern edge of the Michigan Basin, source rocks for petroleum in the Silurian Niagara and Salina Groups have been identified in the Middle Silurian Eramosa Formation (an interreef facies of the Niagara Group) and the Upper Silurian Salina A-1 Carbonate (within the Salina Group) (Powell and others, 1984; Obermajer and others, 2000). Although not yet verified, the assumption is that these intervals are also the source rocks for petroleum produced from the Niagara and Salina Groups in the U.S. portion of the basin. Powell and others (1984) collected 35 quarry and subsurface samples in Ontario, Canada; 19 samples were from the Eramosa Formation and 16 samples from the Salina Group. Nine of the Eramosa Formation samples and two of the Salina Group samples had organic-carbon contents >0.5 weight percent. Obermajer and others (2000) collected 18 quarry and subsurface samples in Ontario; 10 samples were from the Eramosa Formation and 8 samples from the Salina A-1 Carbonate. Nine of the Eramosa Formation samples and seven of the Salina A-1 Carbonate samples had organic-carbon contents >0.5 weight percent. A histogram showing organic-carbon contents for these 53 samples is shown in figure 49.

In a study of samples from the Niagara and Salina Groups in Michigan, Gardner and Bray (1984) collected some 300 core samples and reported (1) for 100 samples of reef-platform strata in the Niagara Group, organic-carbon contents averaged 0.12 weight percent, with organic-carbon contents for 99 percent of the samples <0.3 weight percent; (2) for about 100 samples from the upper parts of the reef and reef-flank strata in the "Brown Niagara" (equivalent to the Middle Silurian Engadine Dolomite in the northern peninsula of Michigan and to the Middle Silurian Guelph Dolomite in Ontario), organic-carbon contents averaged 0.27 weight percent, with organic-carbon contents for 36 percent of the samples ranging from 0.3 to 0.5 weight percent; (3) for 50 Salina A-1 Carbonate samples, organic-carbon contents averaged 0.28 weight percent, with organic carbon-contents for 40 percent of the samples ≤0.3 weight percent, and a maximum value of 0.6 weight percent; (4) for 29 Salina A-2 Carbonate samples, the average organic-carbon content was 0.17 weight percent;

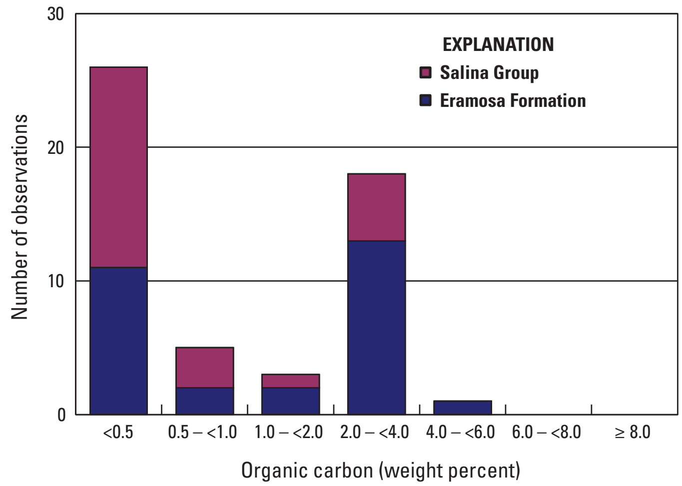


Figure 49. Histogram showing the distribution of organic-carbon contents (in weight percent) for 29 samples collected from the Middle Silurian Eramosa Formation and 24 samples from the Upper Silurian Salina Group from southern Ontario, Canada (Powell and others, 1984; Obermajer and others, 2000).

and (5) for 15 samples of Salina Group anhydrite and halite beds, organic-carbon content averaged 0.04 weight percent. With respect to organic matter thermal maturity and petroleum generation, these presumed Niagara Group and Salina Group petroleum source rocks are within the gas-generation window in the center of the Michigan Basin (fig. 50). Along the northern and southern reef trends, however, most of the Niagara and Salina strata are within the oil window. On the basin margins, the Niagara and Salina strata are thermally immature.

Silurian Niagara Assessment Unit

The Silurian Niagara AU consists of the Niagara Group, which primarily contains carbonate strata. The Niagara Group rests conformably on the Manistique Group and is unconformably overlain by the Salina Group (fig. 51). In the U.S. portion of the Michigan Basin, the Niagara Group, in the subsurface, is divided informally into three units based on color, texture, and well-log response. From base to top these are White Niagara, Gray Niagara, and Brown Niagara. The White Niagara is equivalent to the lower part of the Lockport Dolomite, the Gray Niagara is equivalent to the upper part of the Lockport Dolomite, and the Brown Niagara is equivalent to the Engadine Dolomite in the northern peninsula of Michigan and to the Guelph Dolomite in Ontario, Canada. The thickness of the Niagara Group ranges from 100 to 500 ft throughout much of the Michigan Basin (fig. 52), although thickness may increase to 600 ft over some pinnacle reefs within the Niagara Group. Elevations at the top of the Brown Niagara in the basin range from about 500 to 8,500 ft below sea level (fig. 53); elevations at the top of the Gray Niagara range from about 500 to 8,000 ft below sea level (fig. 54).

The base map for this figure is from Nicholson and others (2004).

Figure 50. Map showing the thermal maturity of organic matter in the Middle Silurian Niagara Group and the Upper Silurian Salina Group in the central part of the Michigan Basin based on conodont color alteration index (CAI). The CAI contours are based on limited data. With respect to petroleum generation, CAI values <1.5 = immature; CAI from 1.5 to 2.5 = oil window; and CAI from 2.5 to 3.0 = gas window.

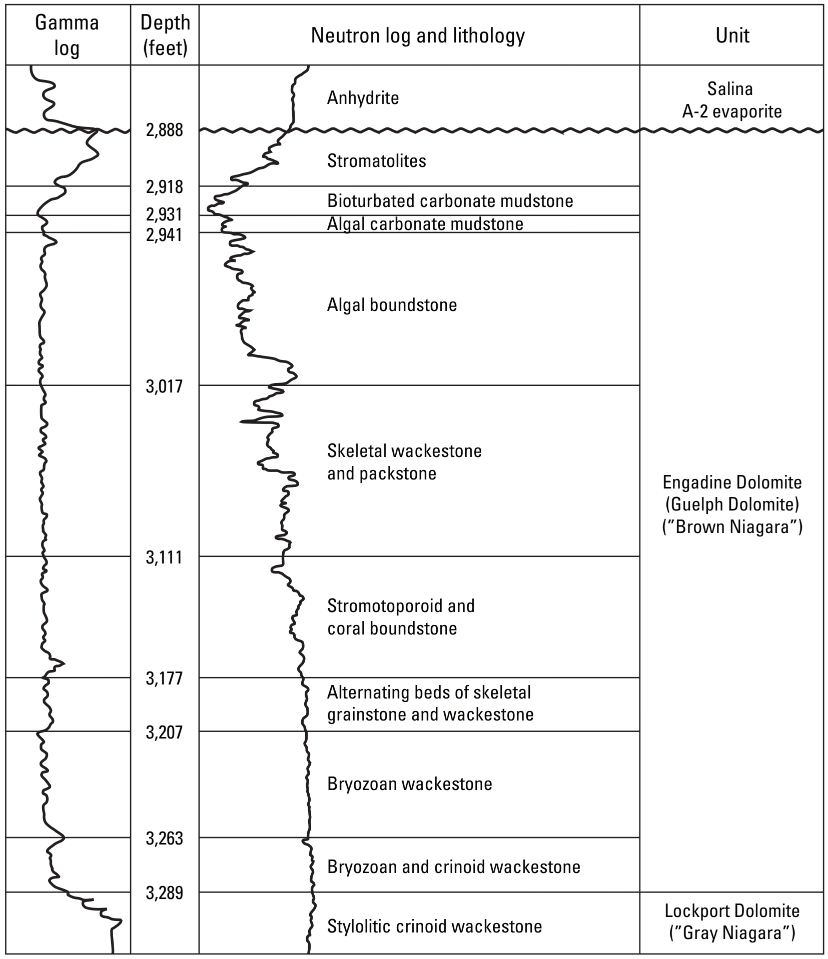


Figure 51. Stratigraphy of the Middle Silurian Engadine Dolomite (and equivalent Guelph Dolomite) and the Upper Silurian Salina A-2 evaporite (see fig. 5) in the Michigan Consolidated Gas Company Radike and others No. 1 well, St. Clair County, Michigan (modified from Gill, 1977a). Brown and Gray Niagara are informal units of the Niagara Group.

The base map for this figure is from Nicholson and others (2004).

Figure 52. Map of isopachs of the Middle Silurian Niagara Group in the central part of the Michigan Basin (from Gardner and Bray, 1984).

The base map for this figure is from Nicholson and others (2004).

Figure 53. Structure map on top of the Middle Silurian informal Brown Niagara of Niagara Group and correlative strata in the central part of the Michigan Basin (from Wylie and Wood, 2005).

The base map for this figure is from Nicholson and others (2004).

Figure 54. Structure map on top of the Middle Silurian informal Gray Niagara of Niagara Group and correlative strata in the central part of the Michigan Basin (from Catacosinos and others, 1990).

The Engadine Dolomite (Guelph Dolomite and Brown Niagara equivalents) in the Niagara Group contains abundant bioherms (interpreted as pinnacle reefs of a carbonate bank and shelf platform; fig. 55) that form a 9- to 15-mi-wide circular zone around the Michigan Basin (Mantek, 1976; Cercone and Lohmann, 1985; Catacosinos and others, 1990, 2001). The bioherms are micritic biostromes that contain corals, stromatoporoids, crinoids, bryozoans, and brachiopods (figs. 56 and 57). On the basinward side of this zone, the bioherms consist primarily of coral-stromatoporoid packstone. Toward the basin, the bioherms are taller and contain more micrite and more crinoids (Sears and Lucia, 1980). In northern Michigan, the Niagara bioherm trend ("northern reef trend") is composed of several hundred individual carbonate build-ups at depths of 4,921 to 7,218 ft below the surface. Some of these build-ups are more than 600 ft in height, but average dimensions are usually 330 ft in height and 3,280 ft in diameter. These bioherms are dolomitic along the outer part of the bioherm zone and have greater porosity and permeability. Toward the basin interior, the bioherms become progressively more calcitic and impermeable. In contrast, the bioherms in southern Michigan have been dolomitized completely, and they tend to be smaller in size. In general, the bioherms along the northern reef trend occur with greater density, and they attain predictably greater heights in a basinward direction than do the bioherms along the southern part of the reef trend.

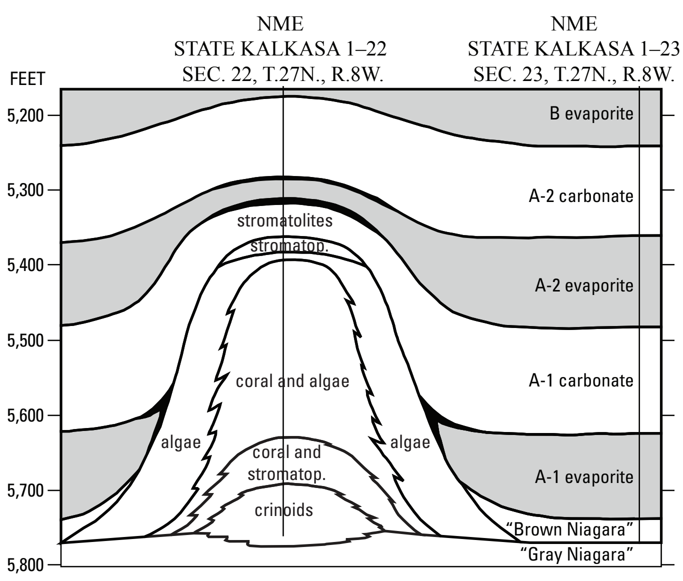


Figure 55. Profile through a pinnacle reef in the Middle Silurian Niagara Group from the northern Silurian reef trend in Michigan (from Mantek, 1973). Brown and Gray Niagara are informal units of the Niagara Group. Evaporites and carbonates overlying the Niagara are within the Salina Group. Black denotes anhydrite; gray denotes halite; stromatop., stromatoporoids.

Assessment Unit Model

The Silurian Niagara AU contains conventional petroleum accumulations. In Ontario, Canada, on the eastern edge of the Michigan Basin, source rocks for petroleum in the Niagara and Salina Groups have been identified in the Eramosa Formation and the Salina A-1 Carbonate (within the Salina Group) (Powell and others, 1984; Obermajer and others, 2000). Although not yet verified, the assumption is that equivalent stratigraphic intervals in the U.S. part of the Michigan Basin are the source rocks for petroleum found in the Niagara and Salina Groups in the U.S. portion of the basin. Some petroleum generation may have occurred from these source-rock intervals during the Late Devonian (coincident with the Acadian orogeny) when the Niagara and Salina Groups may have entered the oil window in the center of the basin (Hayba, 2005). Subsequently, during the Pennsylvanian and Permian (coincident with the Alleghanian orogeny), Niagara and Salina strata in the central part of the basin entered the gas window and continued to generate petroleum. Today, the Niagara and Salina strata in the central part of the basin are within the gas-generation window (fig. 50). Along the northern and southern reef trends, however, most of the Niagara and Salina strata are within the oil window.

The reservoirs in the Silurian Niagara AU are stratigraphic traps consisting of bioherms ("reefs") and associated sedimentary accumulations on the bioherm flanks in the "Brown" Niagara. Evaporites of the overlying Salina Group act as reservoir seals (Budros and Briggs, 1977; Gill, 1977b; Catacosinos and others, 1990).

Reservoir Characteristics

Reservoirs in the Silurian Niagara AU have produced both oil and gas (fig. 58). Gas is more common on the basinward (that is, deeper) side of the reef trends, whereas oil is more common at greater distances from the center of the basin (Gill, 1979; see also fig. 58). Most of the reservoirs are bioherms ("pinnacle reefs") of the "Brown" Niagara, although Ells (1979a) describes two fields in which Niagara Group petroleum production is not from bioherms (Fowlerville and Howell fields in Livingston County, Michigan) (fig. 58). Niagara Group petroleum production that is not from bioherms has also been reported from Manistee County, Michigan. Nevertheless, most Niagara Group oil and gas production is from discrete and isolated bioherms with solution-enhanced porosity in completely dolomitized rock (Mantek, 1976; Catacosinos and others, 1990). A few limestone (nondolomitized) bioherms have been encountered on the basinward side of the reef trend, but these limestone bioherms have been much less productive than the dolomitized bioherms.

Along the "Brown Niagara" bioherm trend ("northern reef trend") of the Michigan Basin, the bioherms occur at depths of 3,000 to 7,000 ft, and they attain heights of over

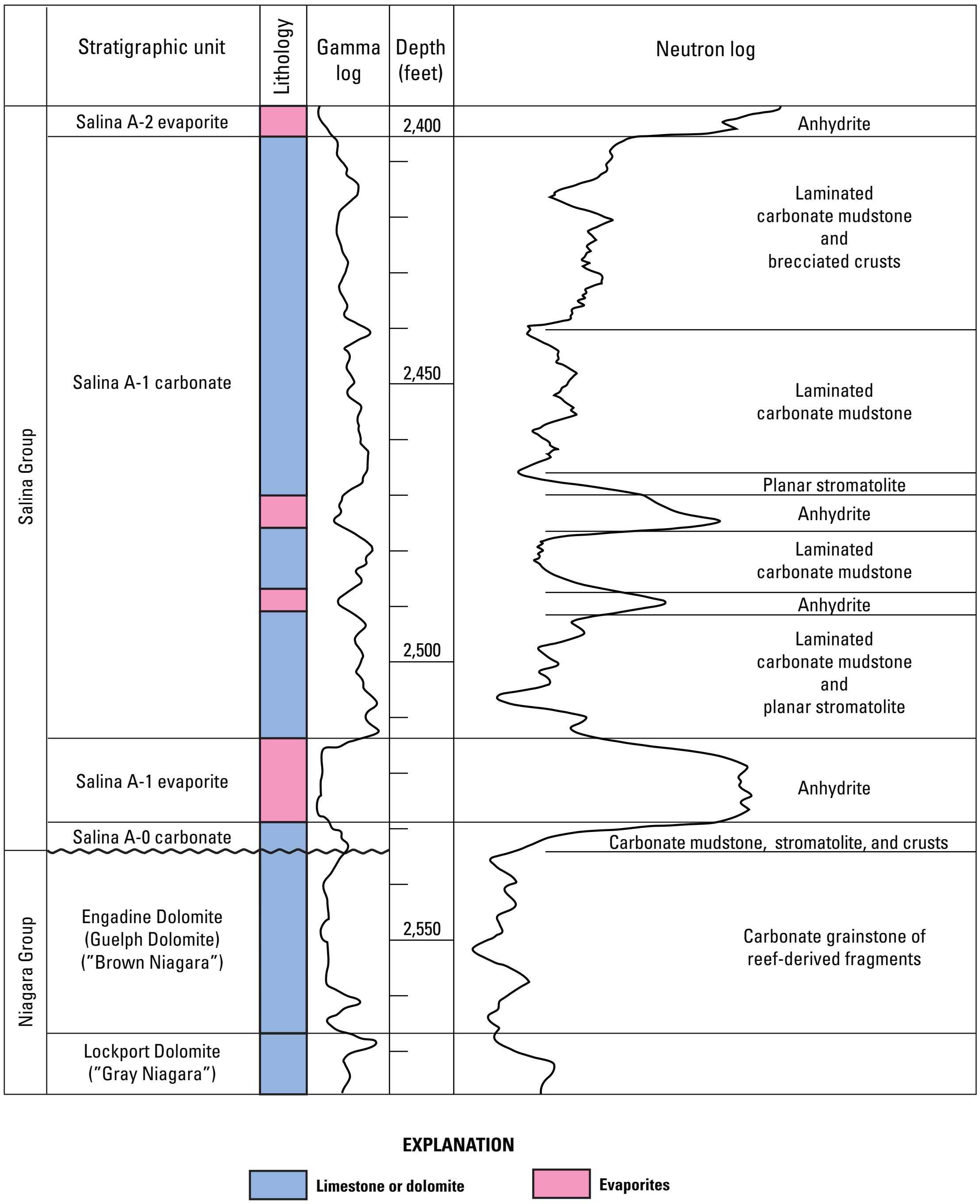
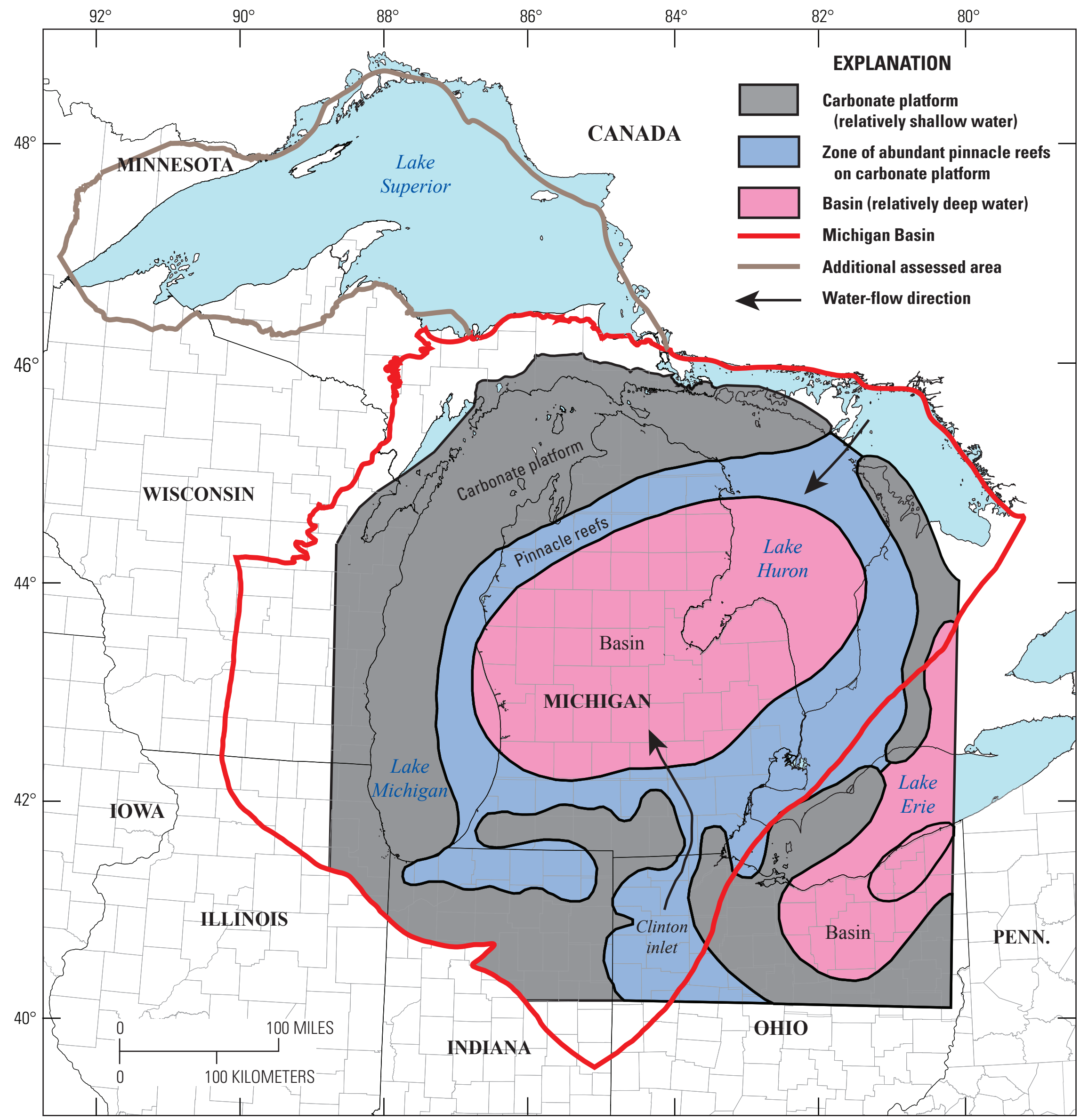
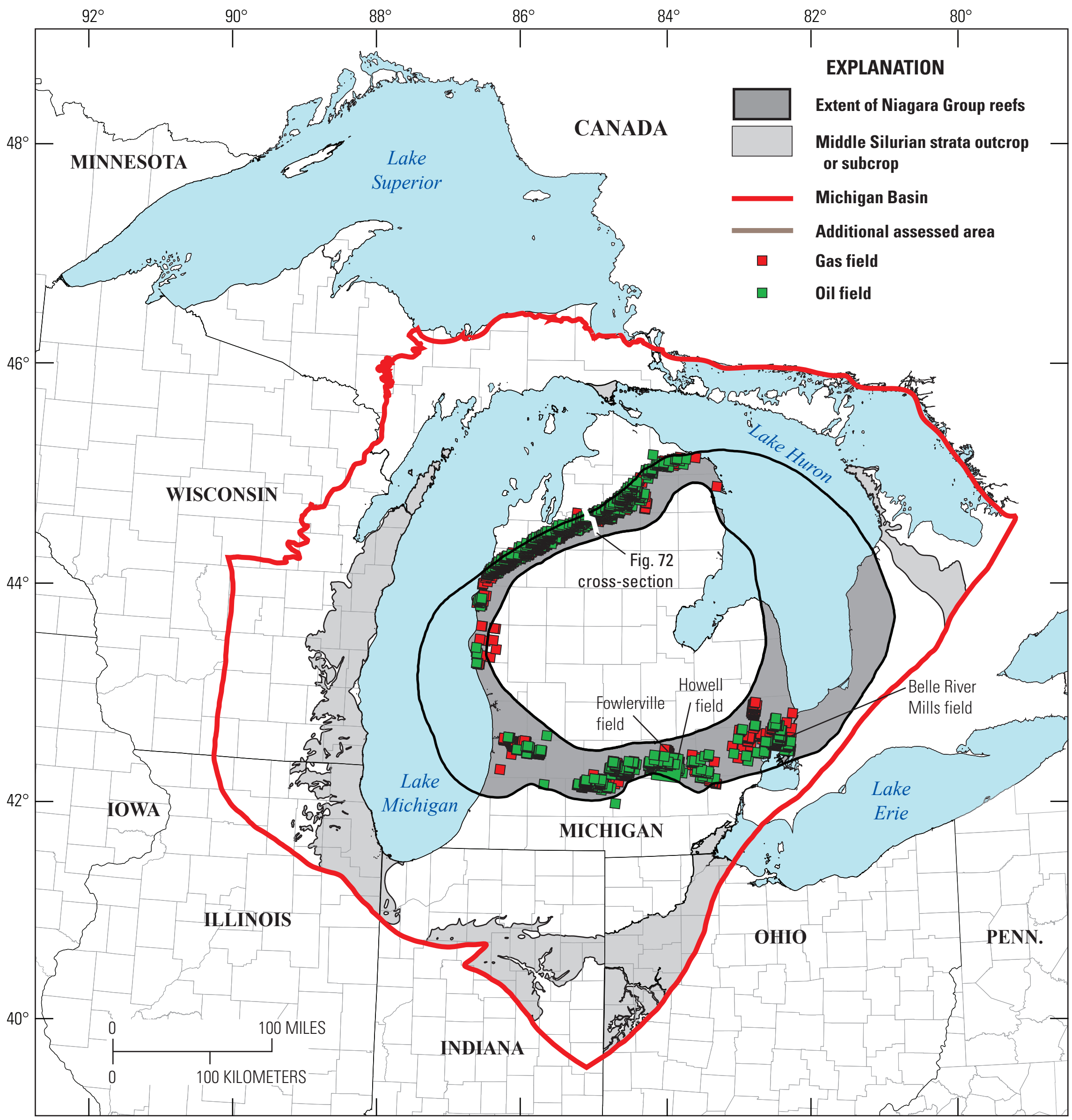


Figure 56. Well log through pinnacle reef (from Bentley, 1979). Scales for gamma log and neutron log are not given. Brown and Gray Niagara are informal units of the Niagara Group.



The base map for this figure is from Nicholson and others (2004).

Figure 57. Map showing the paleogeography during the Middle Silurian in the central part of the Michigan Basin (after Gill, 1985). Arrows denote directions of water flow into the basin.



The base map for this figure is from Nicholson and others (2004).

Figure 58. Map showing the locations of oil and gas fields where production is from reservoirs in the Middle Silurian Niagara Group reefs in the U.S. portion of the Michigan Basin (from U.S. Geological Survey Web site http://energy.cr.usgs.gov/oilgas/noga). Identified fields are discussed in the text; Figure 72, line of cross section shown in figure 72.

600 ft, according to Mantek (1976), Catacosinos and others (1990), and Schneider and others (1991). Most of these northern bioherms range in size from 40 to 600 acres, with the average size being approximately 80 acres. Core porosities in productive bioherms range from 3 to 37 percent, with average net pay porosity at 6 percent. Permeabilities are variable because of variable pore geometries, the sporadic distribution of vugular and fracture porosity, and the general lack of matrix porosity. Net pay thicknesses can vary from 8 to 400 ft. Water saturations usually range from 15 to 25 percent.

Wylie and Wood (2005) provide detailed descriptions of the Belle River Mills field in St. Clair County, Michigan. This field was discovered in 1961 and produced over 21 BCFG from a "Brown Niagara" bioherm before the field was converted to gas storage in 1965. Core permeability measurements from this field range from zero to 8 darcies (50 percent of the core permeability measurements are <2 md; 40 percent of the core-permeability measurements range from 2 to 100 md), and core-porosity measurements from this field range to as much as 33 percent (15 percent of the core-porosity measurements are <2 percent, and 83 percent of the core-porosity measurements range from 2 to 20 percent).

Along the southern "Brown Niagara" bioherm (southern reef trend) of the Michigan Basin, bioherm heights range from 200 to 350 ft, average height is approximately 325 ft, and areal extent of individual bioherms ranges from 40 to 800 acres (Mantek, 1976; Catacosinos and others, 1990; and Matson, 1991). In contrast with bioherms in the northern reef trend, the southern bioherms have been completely dolomitized. Net pay porosities in the southern reef-trend bioherms are about 5 to 6 percent. According to Mantek (1976), the bioherms are generally gas-prone in southeastern Michigan, and they are generally oil-prone in south-central Michigan. Along the southern reef trend in Calhoun County in south-central Michigan, the extent of an individual bioherm usually ranges from 40 to 60 acres; they contain oil with low gas-to-oil ratios, have high oil-water contacts, and may have a partial water drive (Mantek, 1976). Barratt (1981) provides detailed descriptions of three wells that discovered oil and gas in 1981 in the southern reef trend in Eaton County, Michigan. These wells had about 150 ft of net pay, with porosities ranging to 23 percent, and with an average porosity of 12 percent.

Petroleum Geochemistry

A gas chromatogram of the saturated-hydrocarbon fraction for oil collected from a well producing from the Niagara Group in the Grant 26 field in Grand Traverse County, Michigan is shown in figure 59 (chromatogram modified from Rullkötter and others, 1986, their fig. 4). The saturated-hydrocarbon distribution is characterized by an odd-carbon predominance in the n-C_{20} to n-C_{26} alkanes, relatively abundant amounts of isocyclic compounds, and a low pristine/phytane ratio. The carbon preference index (CPI, modified from Bray and Evans, 1961) between n-C_{20} and n-C_{26} is 1.07, the pristane/phytane ratio is approximately 0.38, and the

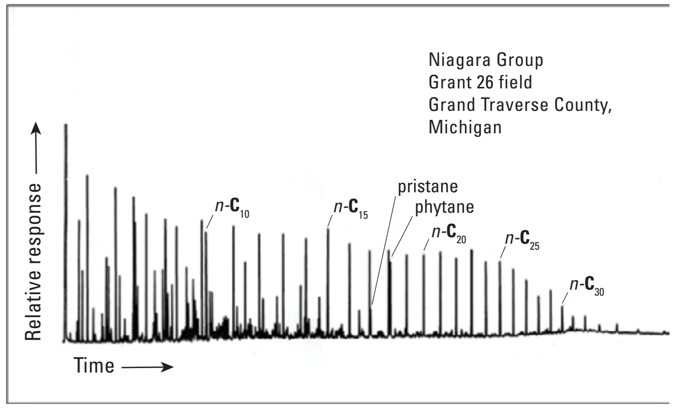


Figure 59. Saturated-hydrocarbon-fraction gas chromatogram for oil collected from a well producing from a reservoir in the Middle Silurian Niagara Group in the Grant 26 field, Grand Traverse County, Michigan (modified from Rullkötter and others, 1986, their fig. 4). The reservoir depth is approximately 6,300 feet.

pristane/n-C_{17} ratio is 0.31 (all values are from measurements of peak height). The saturated-hydrocarbon distribution for this oil is very similar to the distributions of Silurian oils illustrated in Illich and Grizzle (1983) and in Powell and others (1984).

Powell and others (1984) and Obermajer and others (2000) show that the saturated-hydrocarbon distributions from rock extracts of the Eramosa Formation and the Salina A-1 Carbonate in Ontario, Canada, are similar to those of oils in Silurian reservoirs in Ontario. This observation suggests that the organic-rich intervals within the Eramosa Formation and Salina A-1 Carbonate in Ontario and equivalent strata in Michigan are the likely source rocks for petroleum produced from Silurian reef reservoirs in the basin. Obermajer and others (2000) also noted that some Silurian oils had compositions that suggest mixing of Silurian oils with oils from the underlying Middle Ordovician Trenton Formation.

A plot of oil/condensate gravity (°API [American Petroleum Institute]) versus reservoir depth for petroleum produced from Niagara Group and Salina Group reservoirs in the eastern part of the reef trend in northern Michigan and in the central and eastern parts of the reef trend in southern Michigan is shown in figure 60. As shown in this figure, gravity ranges from 33 to 77 °API for oils and condensates produced from the eastern part of the reef trend in northern Michigan to 18 to 49 °API for oils and condensates from the central part, and 29 to 43 °API for oils produced from the eastern part of the reef trend in southern Michigan. In the eastern part of the northern reef trend, only one oil/condensate sample had a value that was less than 40 °API, and most oil/condensate samples with values greater than 50 °API were found at depths greater than 4,500 ft, suggesting greater thermal maturity in this area. In the central part of the southern reef trend, many oil samples had values of less than 30 °API suggesting that these oils may have experienced biodegradation.

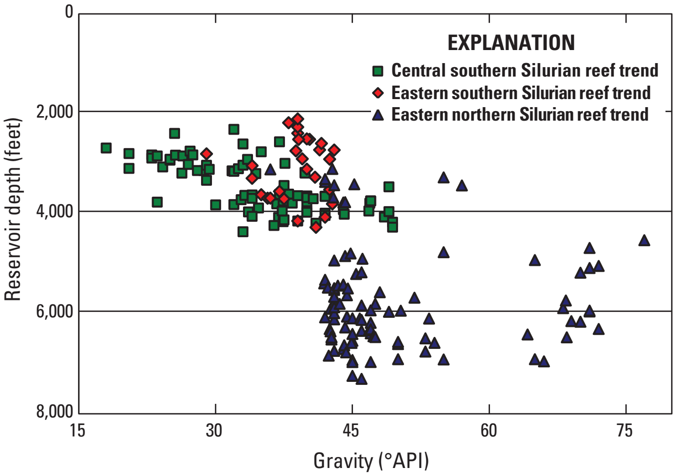


Figure 60. Plot of oil or condensate gravity (°API) versus reservoir depth (surface datum) for petroleum samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group in the central (central southern) and eastern (eastern southern) parts of the Silurian reef trend in southern Michigan and from the eastern (eastern northern) part of the Silurian reef trend in northern Michigan. API = American Petroleum Institute.

The chemical compositions (N_2 mole percent, CO_2 mole percent, H_2S mole percent, ethane/isobutane mole percent/ mole percent, and gas wetness percent) of 1,567 samples of natural gas produced from Niagara Group and Salina Group reservoirs are separated into three distinct groups that are summarized in tables 5, 6, and 7. Table 5 summarizes chemical analyses of 1,335 natural gas samples from the part of the reef trend in northern Michigan, table 6 summarizes chemical analyses of 167 natural gas samples from the central part of the reef trend in southern Michigan, and table 7 summarizes chemical analyses of 65 natural gas samples from the eastern part of the reef trend in southern Michigan. The data summarized in tables 5, 6, and 7 are from Moore and Sigler (1987), Hamak and Sigler (1991), and two data sets, Michigan Oil and Gas Well Gas Analyses Data and Michigan Public Service Commission MichCon "TIPS" Data from the Michigan Geological Repository for Research and Education at Western Michigan University (http://wsh060.westhills.wmich.edu/MGRRE/data/). The data illustrated in the geographic distribution plots and graphs shown in figure 61 through 69 are also from these data sets.

Summary data in tables 5, 6, and 7 demonstrate that natural gas chemical compositions vary both within and between areas and also change as a function of depth. Median gas wetness along the northern reef trend is 26 percent, whereas median gas wetnesses in the central and southeastern parts of the southern reef trend are much less (12 and 14 percent, respectively). A graph of gas-wetness values versus depth for reservoirs in the eastern part of the northern reef trend (Presque Isle, Montmorency, Otsego, and Crawford Counties, Michigan) and in the eastern part of the southern reef trend (St. Clair and Macomb Counties, Michigan) is shown in figure 61. This graph shows a very large range of gas-wetness values (from 10 to near 70 percent) between depths of 3,000 and 7,000 ft. In contrast, gas-wetness values are lower at depths less than 3,000 ft and at depths greater than 7,000 ft.

Contents of H_2S in natural gases in most Niagara Group and Salina Group reservoirs are <0.01 mole percent in both the northern and southern parts of the reef trend (fig. 62). Content of H_2S, however, may range to as much as 6.4 mole percent in gases from some reservoirs in the western part of the reef trend in Mason and Manistee Counties in northern Michigan and in the central part of the reef trend in Kalkaska, Crawford, and Otsego Counties, also in northern Michigan. The area of higher H_2S content in gases in Kalkaska, Crawford, and Otsego Counties coincides with the area of greatest depths (>6,500 ft) of the Niagara Group and Salina Group reservoirs. Geographic distribution of CO_2 contents in gases is shown in figure 63**,** and although higher CO_2 contents are present at a number of locations in the reef trends in both the northern and southern parts of Michigan, higher CO_2 contents are more common in areas with higher H_2S contents. Figures 64 and 65 are plots of H_2S content versus CO_2 content for 56 and 65 natural gas samples that were collected from reservoirs in townships with the highest H_2S contents. Figure 64 shows data from T. 19 N., R. 17 W., T. 19 N., R. 18 W., and T. 19 N., R. 20 W. in Mason County, and T. 24 N., R. 13 W. and T. 22 N., R. 16 W. in Manistee County, Michigan. Figure 65 shows data from T. 28 N., R. 5 W., T. 27 N., R. 6 W., and T. 27 N., R. 7 W. in Kalkaska County, and T. 28 N., R. 3 W. and T. 28 N., R. 4 W. in Crawford County, and T. 29 N., R. 2 W. in Otsego County, Michigan. Both plots show that higher CO_2 contents in gas are generally associated with higher H_2S contents. They also show a wide range in H_2S contents, from <0.01 to 4.0 mole-percent H_2S in Mason and Manistee Counties and from <0.01 to 5.9 mole-percent H_2S in Kalkaska, Crawford, and Otsego Counties. The relation between (a) higher H_2S and higher CO_2 contents and (b) highly variable H_2S and CO_2 contents suggest that both gases are, at least in part, products of thermo-chemical sulfate-reduction reactions between SO_4^{-2} (from Silurian evaporates) and C_2^+ compounds (from petroleum). Similar situations are described in Orr (1974, 1982) for Paleozoic oils in the Big Horn Basin in Wyoming, and in Worden and Smalley (1996) for deep carbonate gas reservoirs in Abu Dhabi. The relation (a and b above) shown for H_2S-enriched gases in the Silurian reefs can also be demonstrated (see Middle Devonian Carbonates AU section) for natural gases produced from reservoirs in the Middle Devonian Detroit River Group in central Michigan where H_2S contents in gas can reach 24 mole percent.

Sulfur contents in 21 oil samples from the reef trend in northern Michigan range from 0.20 to 0.72 weight percent sulfur (Illich and Grizzle, 1983), with the highest sulfur contents found in oils from Manistee and Wexford Counties, in northwestern Michigan. Sulfur contents for 26 oil samples from the reef trend in southern Michigan range from 0.58 to 4.0 weight

Table 5. Statistical summary of the chemical composition of 1,335 natural gas samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group in the reef trend in northern Michigan. The samples were primarily from Crawford, Grand Traverse, Kalkaska, Manistee, Mason, Otsego, Presque Isle, and Wexford Counties.

[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	1,335	1,335	288	1,335	1,335
Median	0.81	0.08	<0.01	5.6	26
Average, Standard deviation	1.0 ± 0.81	0.38 ± 0.95	0.26 ± 0.73	5.9 ± 2.9	28 ± 13
Range	0.06–5.8	<0.01–7.5	<0.01–6.4	0.9–20	6.6–85

Table 6. Statistical summary of the chemical compositions of 167 natural gas samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group in the central part of the reef trend in southern Michigan. The samples were primarily from Calhoun, Eaton, Livingston, and Washtenaw Counties.

[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	167	167	167	161	167
Median	9.3	0.12	<0.01	10.7	14
Average, Standard deviation	9.0 ± 3.4	0.39 ± 1.3	<0.01 ± <0.01	11 ± 3.7	15 ± 6.2
Range	<0.01–19	<0.01–13	<0.01–0.01	2.6–31	1.9–45

Table 7. Statistical summary of the chemical compositions of 65 natural gas samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group in the reef trend in southeastern Michigan. The samples were primarily from Macomb and St. Clair Counties.

[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	65	65	65	65	65
Median	4.1	0.10	<0.01	5.3	12
Average, Standard deviation	3.9 ± 2.3	0.68 ± 1.6	0.02 ± 0.06	5.7 ± 1.7	14 ± 7.0
Range	<0.01–11	<0.01–10	<0.01–0.29	3.6–13	8.0–42

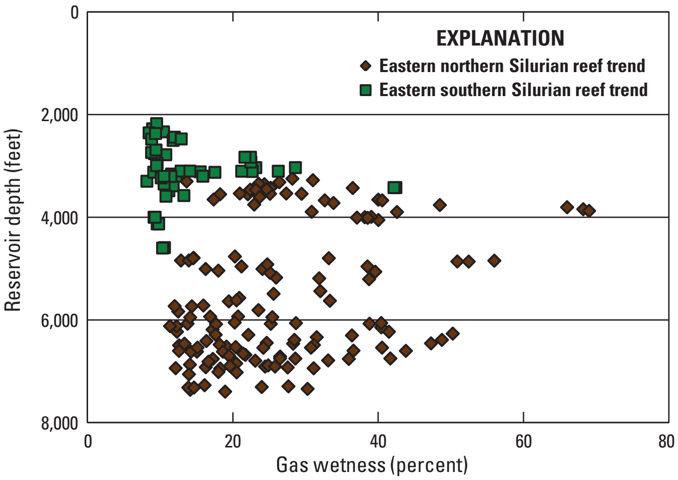


Figure 61. Plot of gas wetness (percent) versus reservoir depth (surface datum) for natural gas samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group in the eastern part of the Silurian reef trend in southern Michigan (number of samples (n) = 52) and from the eastern part of the Silurian reef trend in northern Michigan (n=147). Gas wetness percent = 100 × (1 – [C_1 mole percent /ΣC_1–C_5 mole percent]).

percent S (Illich and Grizzle, 1983), with the highest sulfur contents found in oils from Allegan and Calhoun Counties, Michigan, in the central and west-central part of the trend. H_2S contents of natural gases from reservoirs in the reef trend in southern Michigan are minimal, with H_2S contents >0.1 mole percent for only 4 of 232 gas samples. The maximum H_2S content was 0.29 mole percent for a gas sample from Oakland County, in southeastern Michigan.

Median N_2 contents of natural gases in Niagara Group and Salina Group reservoirs are 0.81 mole-percent N_2 for samples from the reef trend in northern Michigan, and 4.1 mole-percent N_2 and 9.3 mole-percent N_2 for samples from the eastern and central parts, respectively, of the reef trend in southern Michigan (tables 5, 6, and 7). The geographic distribution of N_2 contents for gas samples from reservoirs in the Niagara Group and Salina Group in Michigan is shown in figure 66. Figure 67 shows that N_2 contents of gases are generally higher in reservoirs at shallow depths (for example, eastern part of the reef trend in southern Michigan) and lower in reservoirs at greater depths (for example, eastern part of the reef trend in northern Michigan). This distribution suggests that gas N_2 contents may be related to thermal maturity of the petroleum source rock.

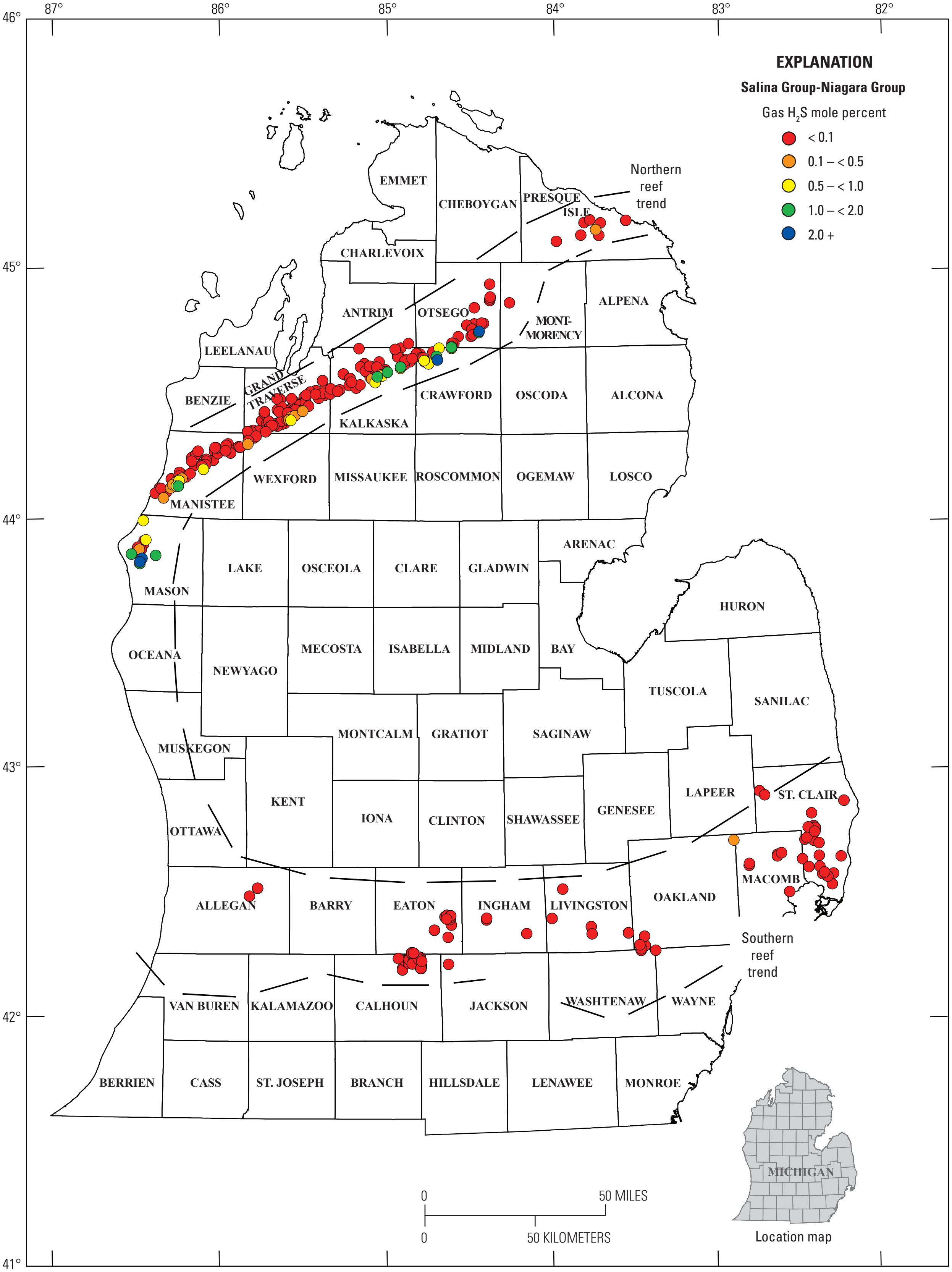
The geographic distribution of ethane/isobutane for gas samples from Niagara Group and Salina Group reservoirs in the Michigan Basin is shown in figure 68. Ethane/isobutane ratios in natural gases produced from the Niagara Group and the Salina Group are relatively low along the reef trend in northern Michigan (median ethane/isobutane = 5.6) and along the eastern part of the reef trend in southern Michigan (median ethane/isobutane = 5.3). Ethane/isobutane ratios are relatively higher along the central part of the reef trend in southern Michigan (median ethane/isobutane = 10.7).

A graph of N_2 content versus ethane/isobutane of natural gases produced from Niagara Group and Salina Group reservoirs in the central and eastern parts of the reef trend in southern Michigan and from Trenton Formation reservoirs in Calhoun County (southern Michigan) is shown in figure 69. This graph shows that compositions of gases from Niagara Group and Salina Group reservoirs along the central part of the reef trend in southern Michigan are intermediate between those of gases from Niagara Group and Salina Group reservoirs from the eastern part of the reef trend in southern Michigan and gases from Trenton Formation reservoirs. This observation suggests that gases from Niagara Group and Salina Group reservoirs in the central part of the reef trend are mixtures of gases from Silurian petroleum source rocks and gases from petroleum source rocks in the underlying Trenton Formation. This suggestion is supported by the observations of Obermajer and others (2000) that some Silurian oils from the reef trend in southern Michigan had compositions that suggested mixing of Silurian-type oils with Ordovician-type oils from the underlying Trenton Formation.

Undiscovered Petroleum Resources

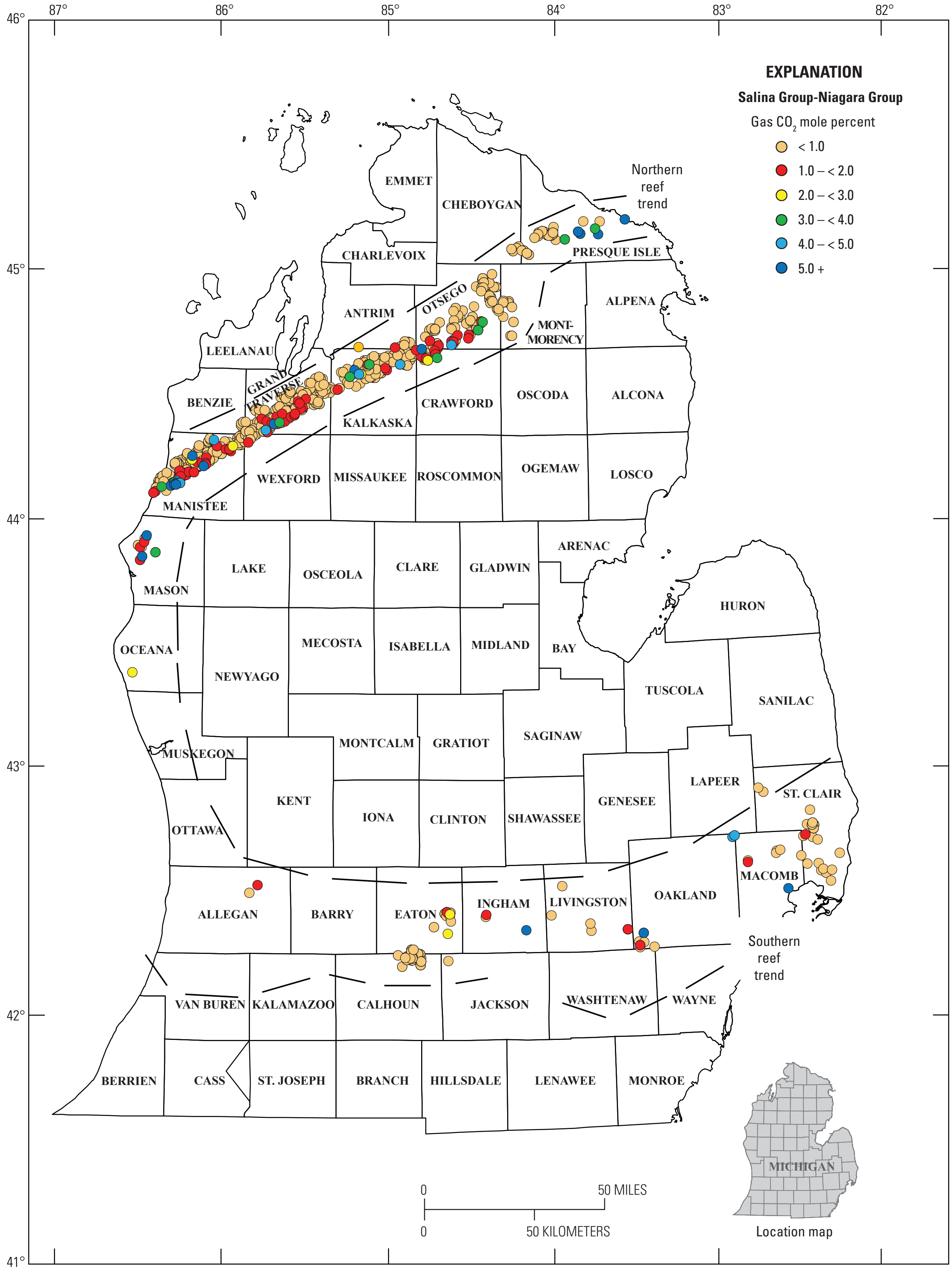
In the 2004 assessment of the U.S. portion of the Michigan Basin, the USGS assessed the Silurian Niagara AU as a conventional petroleum accumulation. The assessment unit was considered to be primarily oil-prone, but the undiscovered fields were estimated to include both oil and gas fields. For the oil fields, the estimated volumes of undiscovered, technically recoverable resources of oil are 95.6 MMBO at the 95-percent certainty level, 208 MMBO at the 50-percent certainty level, 336 MMBO at the 5-percent certainty level, and a mean of 211 MMBO. For the associated natural gas, the estimated volumes are 179 BCGF at the 95-percent certainty level, 415 BCFG at the 50-percent certainty level, 759 BCFG at the 5-percent certainty level, and a mean of 435 BCFG. For the associated natural gas liquids, the estimated volumes are 12.7 MMBNGL at the 95-percent certainty level, 31.4 MMBNGL at the 50-percent certainty level, 63.5 MMBNGL at the 5-percent certainty level, and a mean of 33.9 MMBNGL (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).

For the gas fields, the estimated volumes of undiscovered, technically recoverable natural gas resources are 287 BCGF at the 95-percent certainty level, 623 BCFG at the 50-percent certainty level, 1.04 TCFG at the 5-percent certainty level, and a mean of 640 BCFG. For natural gas liquids, the estimated volumes are 16.7 MMBNGL at the 95-percent certainty level, 38.9 MMBNGL at the 50-percent certainty level, 72.5 MMBNGL at the 5-percent certainty level, and a mean of 41.0 MMBNGL (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 62. Map showing the geographic distribution of hydrogen sulfide (H_2S) contents (mole percent) for 520 natural gas samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group in the Silurian reef trends in northern and southern Michigan.



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 63. Map showing the geographic distribution of carbon dioxide (CO_2) contents (mole percent) for 520 natural gas samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group in the Silurian reef trends in northern and southern Michigan.

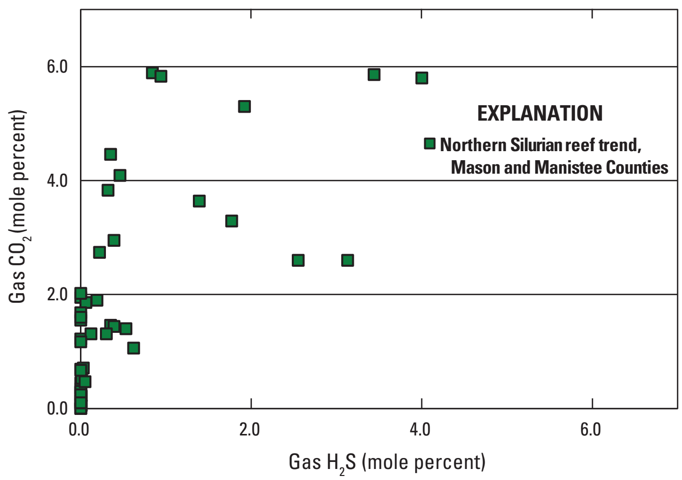


Figure 64. Plot of hydrogen sulfide (H_2S) content (mole percent) versus carbon dioxide (CO_2) content (mole percent) for 56 natural gas samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group at the western end of the Silurian reef trend in T. 19 N., R. 17 W., T. 19 N., R. 18 W., and T. 19 N., R. 20 W., Mason County, and from T. 24 N., R. 13 W. and T. 22 N., R. 16 W., Manistee County, northwestern Michigan.

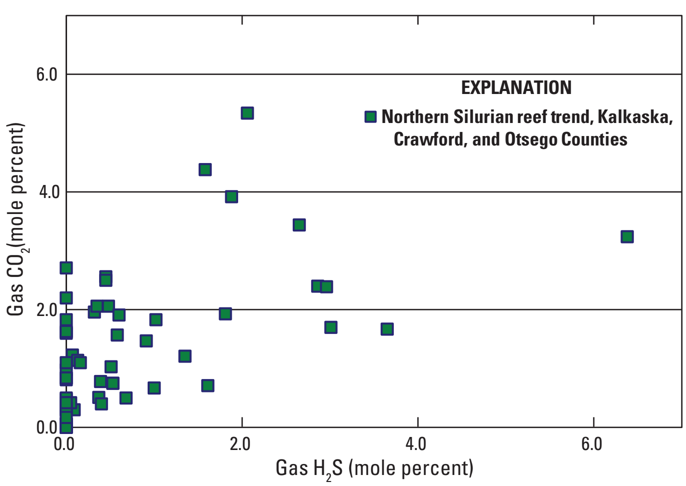


Figure 65. Plot of hydrogen sulfide (H_2S) content (mole percent) versus carbon dioxide (CO_2) content (mole percent) for 65 natural gas samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group in the Silurian reef trend in T. 28 N., R. 5 W., T. 27 N., R. 6 W., and T. 27 N., R. 7 W., Kalkaska County, T. 28 N., R. 3 W. and T. 28 N., R. 4 W., Crawford County, and T. 29 N., R. 2 W., Otsego County, north-central Michigan.

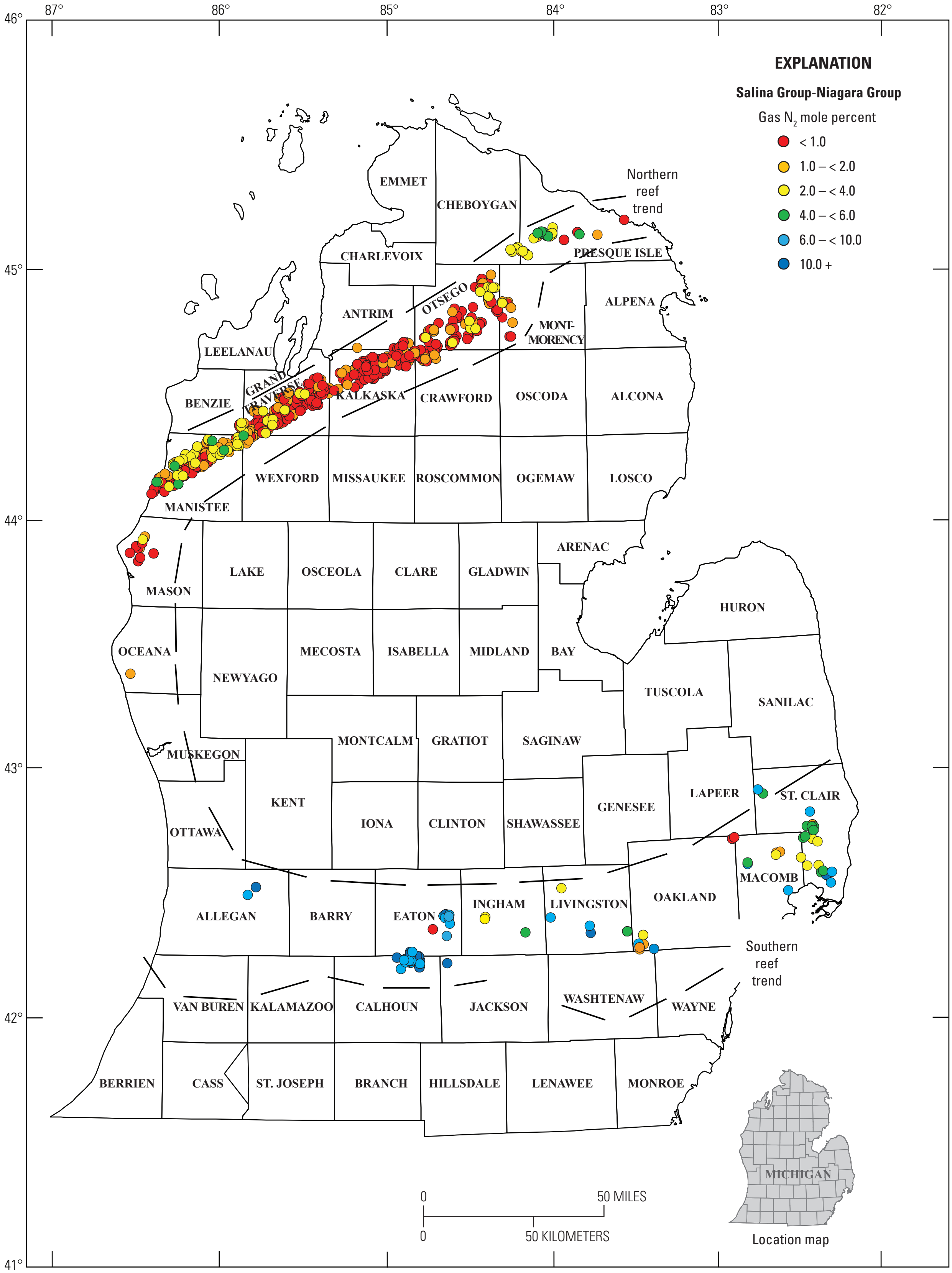
For the assessment calculations, a minimum grown field size of 0.5 MMBO equivalent was used for oil fields, and a minimum grown field size of 3 BCFG was used for gas fields. As of 2004, the Silurian Niagara AU contained 222 known oil fields and 157 known gas fields with grown field sizes exceeding the minimum sizes. Also, as of 2004, the assessment unit was estimated to have produced a cumulative of 468 MMBO and 2,777 BCFG in Michigan. The numbers of undiscovered accumulations greater than the minimum grown field size were estimated as follows: minimum = 1 oil accumulation and 1 gas accumulation, mode = 20 oil accumulations and 20 gas accumulations, and maximum = 60 oil accumulations and 60 gas accumulations. The sizes of undiscovered accumulations greater than the minimum grown field size were estimated as follows: minimum = 0.5 MMBO and 3 BCFG, median = 0.9 MMBO and 7 BCFG, and maximum =20 MMBO and 60 BCFG.

Silurian Salina A-1 Carbonate Assessment Unit

The Silurian A-1 Carbonate AU includes only the informal Upper Silurian Salina A-1 carbonate and only the area where the Salina A-1 carbonate occurs on the basinward side of the Middle Silurian Niagara Group reef trends (area shown on figs. 53 and 58). The Salina A-1 carbonate is also known as the Ruff Formation (Budros and Briggs, 1977) (fig. 5). Throughout the basin, the thickness of the Salina A-1 carbonate (fig. 70) ranges from about 45 to 150 ft; within the area of the assessment unit, thickness is less than 75 ft. Elevations at the top of the Salina A-1 carbonate within the assessment unit area range from about 3,500 to 8,000 ft below sea level (fig. 54).

The Salina A-1 carbonate is part of the Salina Group (figs. 55, 56, 71, and 72), which rests on an unconformity above the Niagara Group (figs. 51, 56, and 71) and is overlain by the Bass Islands Group (Gill, 1977a,b; Catacosinos and others, 1990). The contact with the overlying Bass Islands Group is gradational. The Salina Group has been classified informally (from base to top) into Salina “A” through Salina “G” units (Gill, 1977a,b; Catacosinos and others, 1990). The Salina “A,” “B,” “D,” and “F” units consist of alternating beds of evaporites, carbonate rocks, and shale. In contrast, the Salina “C,” “E,” and “G” units consist predominantly of shale. In the center of the basin, however, the Salina Group consists predominantly of halite and anhydrite, with a few thin beds of carbonate and shale. In the center of the basin, the Salina Group is more than 2,500 ft thick, and it contains some potassium-bearing evaporites (sylvinite, a mixture of halite and sylvite).

Straw (1985) describes many of the stratigraphic details of the lower part of the Silurian Salina Group. The basal unit of the Salina Group is the Salina A unit (fig. 71), which Evans (1950) subdivided (from base to top) informally into the Salina A-1 evaporite, Salina A-1 carbonate, Salina A-2 evaporite, and Salina A-2 carbonate. In some places, a stratigraphic unit called the Salina A-0 carbonate is present below the Salina A-1 evaporite (fig. 71) (Gill, 1977a). In southeastern Michigan, an unconformity may be present between the Niagara Group and the Salina A-0 carbonate (Gill, 1977a). The Salina A-0



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 66. Map showing the geographic distribution of nitrogen (N_2) contents (mole percent) for 520 gas samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group in the Silurian reef trends in northern and southern Michigan.

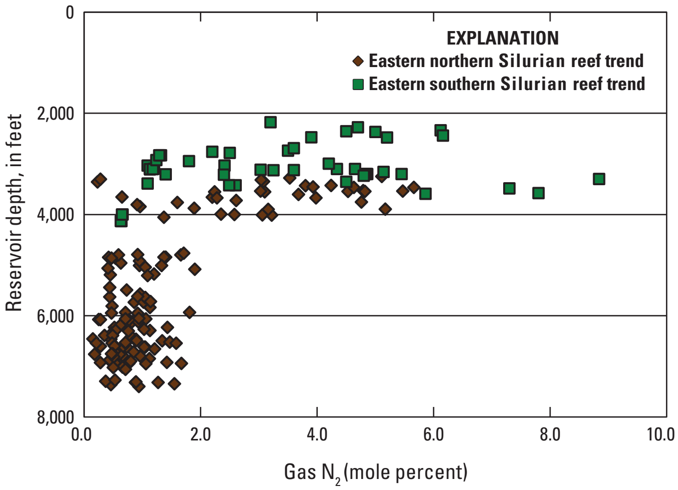


Figure 67. Plot of nitrogen (N_2) content (mole percent) versus reservoir depth (surface datum) for natural gas samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group in the eastern part of the Silurian reef trend in southern Michigan (number of samples [n] = 52), and the eastern part of the Silurian reef trend in northern Michigan (n = 147).

carbonate interfingers with the overlying Salina A-1 evaporite. More precisely, the Salina A-1 evaporite is conformable on the Salina A-0 carbonate and unconformable on older Niagara strata beyond the extent of the Salina A-0 carbonate. Halite and sylvite are present in the central portions of the Salina A-1 evaporite. In plan view, the halite and sylvite are encircled by gypsum and anhydrite, which in turn are encircled by fine-grained carbonate.

The Salina A-1 evaporite is overlain conformably by the Salina A-1 carbonate, which is less than 75 ft thick (fig. 70) and consists predominantly of laminated, dolomitic limestone. The dolomitic limestone is overlain and underlain by halite and anhydrite. Additional descriptions of the Silurian Salina A-1 carbonate may be found in Budros and Briggs (1977), Gill (1977a,b), and Nurmi and Friedman (1977). Where the Salina A-1 carbonate is not present, an unconformity is present on top of the Salina A-1 evaporite.

The Salina A-1 carbonate is overlain by the Salina A-2 evaporite, which is lithologically similar to the Salina A-1 evaporite (figs. 71, 72, and 73). The Salina A-2 Evaporite is conformable with the underlying Salina A-1 carbonate but overlies a disconformity on other rocks beyond the extent of the Salina A-1 carbonate.

Assessment Unit Model

At the time of the 2004 USGS assessment of the Michigan Basin, it was thought that natural gases in the Salina A-1 carbonate reservoirs were derived from Middle Ordovician petroleum source rocks and had migrated upward and along fractures in the central part of the basin. Consequently, during the assessment deliberations, the Silurian A-1 Carbonate AU was associated with the Ordovician to Devonian Composite TPS (Swezey and others, 2005). However, with the acquisition of additional gas chemical analyses, it was concluded that the chemistry of gases within Silurian Salina A-1 carbonate reservoirs is similar to the chemistry of gases within reservoirs of the Silurian Niagara Group. Thus, for this assessment report, the Silurian A-1 Carbonate AU is now part of the Silurian Niagara/Salina TPS.

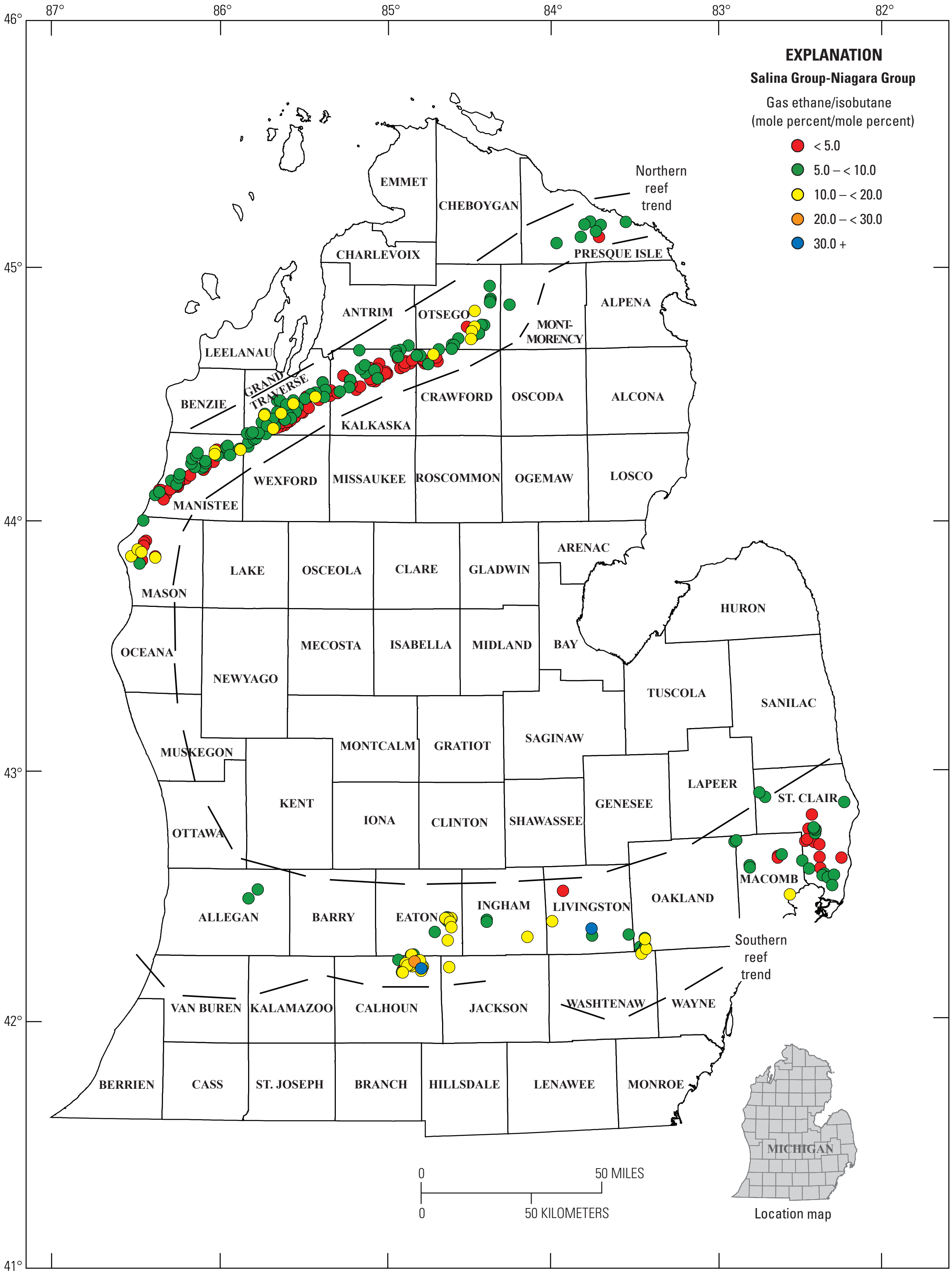
The Silurian A-1 Carbonate AU contains conventional petroleum accumulations. In the Canadian portion of the eastern part of the Michigan Basin, source rocks for petroleum in the Niagara and Salina Groups have been identified in the Eramosa Formation (an interreef facies of the Niagara Group) and the Salina A-1 carbonate (within the Salina Group) (Powell and others, 1984; Obermajer and others, 2000). Although not yet verified, the assumption is that equivalent stratigraphic intervals in the U.S. part of the Michigan Basin are the source rocks for petroleum found in the Silurian A-1 Carbonate AU. Some petroleum generation and migration may have occurred from these intervals during the Late Devonian (coincident with the Acadian orogeny) when the petroleum source rocks may have entered the oil window in the deepest part of the basin (Hayba, 2005). Subsequently, during the Pennsylvanian and Permian (coincident with the Alleghanian orogeny), most of the Niagara and Salina source rocks in the central part of the basin entered the gas window and continued to generate petroleum. Today, the Niagara and Salina Groups strata in the central part of the basin are within the gas-generation window (fig. 50). Along the northern and southern reef trends, however, most of the Niagara and Salina Groups strata are within the oil window.

Reservoir Characteristics

Reservoirs in the Silurian A-1 Carbonate AU are beds of laminated, dolomitic limestone that are overlain and underlain by halite and (or) anhydrite. Petroleum traps in the assessment unit are primarily stratigraphic, and reservoir seals are the overlying and interfingering beds of evaporites within the Salina Group. Most reservoirs in the Silurian A-1 Carbonate AU have produced gas with some associated oil (fig. 74). In some places in the central part of the basin, the Salina A-1 carbonate strata contain gas with H_2S, and the reservoirs are overpressured (Catacosinos and others, 1990).

Petroleum Geochemistry

The chemical compositions (N_2 mole percent, CO_2 mole percent, H_2S mole percent, ethane/isobutane mole percent/mole percent, and gas wetness percent) of 11 samples of natural gas from the Salina A-1 carbonate are summarized in table 8. Ten of the samples are from Tuscola County; one sample is from Oscoda County (Tu and Os, respectively, in



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 68. Map showing the geographic distribution of ethane/isobutane (mole percent /mole percent) for 520 natural gas samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group in the Silurian reef trends in northern and southern Michigan.

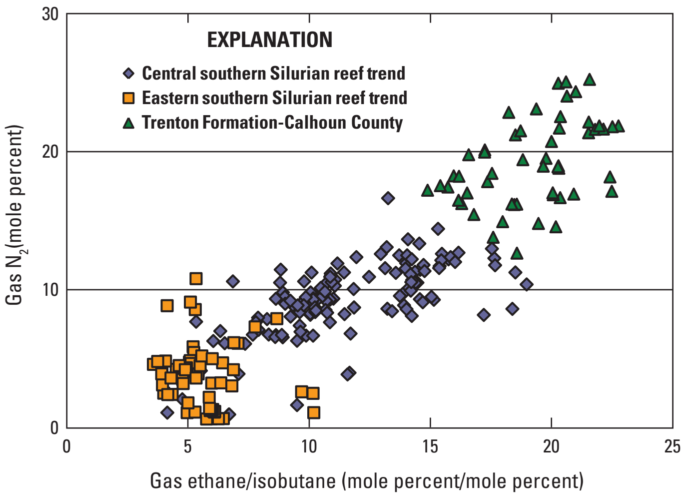


Figure 69. Plot of ethane/isobutane (mole percent/mole percent) versus nitrogen (N_2) content (mole percent) for natural gas samples collected from wells producing from the Middle Silurian Niagara Group and Upper Silurian Salina Group in the central and eastern parts of the Silurian reef trend in southern Michigan, and from the Middle Ordovician Trenton Formation in Calhoun County in south-central Michigan.

fig. 74). These samples were collected from reservoir depths ranging from 6,852 to 8,040 ft. The data summarized in table 8 are from Moore and Sigler (1987), Hamak and Sigler (1991), and two data sets, Michigan Oil and Gas Well Gas Analyses Data and Michigan Public Service Commission MichCon "TIPS" Data from the Michigan Geological Repository for Research and Education at Western Michigan University (http://wsh060.westhills.wmich.edu/MGRRE/data/).

The median and range of gas wetness values, as well as the median contents of H_2S, CO_2, and N_2 of produced gases from Salina A-1 carbonate reservoirs, are similar to the compositional ranges of gases produced from the Silurian Niagara Group and Salina Group reservoirs. Likewise, ethane/isobutane ratios of gases produced from the Salina A-1 carbonate reservoirs are similar to ethane/isobutane ratios of gases produced from Niagara Group and Salina Group reservoirs in the eastern part of the reef trend in northern Michigan and in the eastern part of the reef trend in southern Michigan. These comparisons suggest that both sets of produced gases were generated from the same petroleum source-rock interval.

Undiscovered Petroleum Resources

In the 2004 assessment of the U.S. portion of the Michigan Basin, the USGS assessed the Silurian A-1 Carbonate AU as a conventional petroleum accumulation. The assessment unit was considered to be primarily gas-prone, and the undiscovered fields were estimated to be only gas fields. For the gas fields, the estimated volumes of undiscovered, technically recoverable natural gas resources are 26.3 BCGF at the 95-percent certainty level, 94.6 BCFG at the 50-percent certainty level, 214 BCFG at the 5-percent certainty level, and a mean of 104 BCFG. For natural gas liquids, the estimated volumes are 0.5 MMBNGL at the 95-percent certainty level, 1.8 MMBNGL at the 50-percent certainty level, 4.5 MMBNGL at the 5-percent certainty level, and a mean of 2.1 MMBNGL (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).

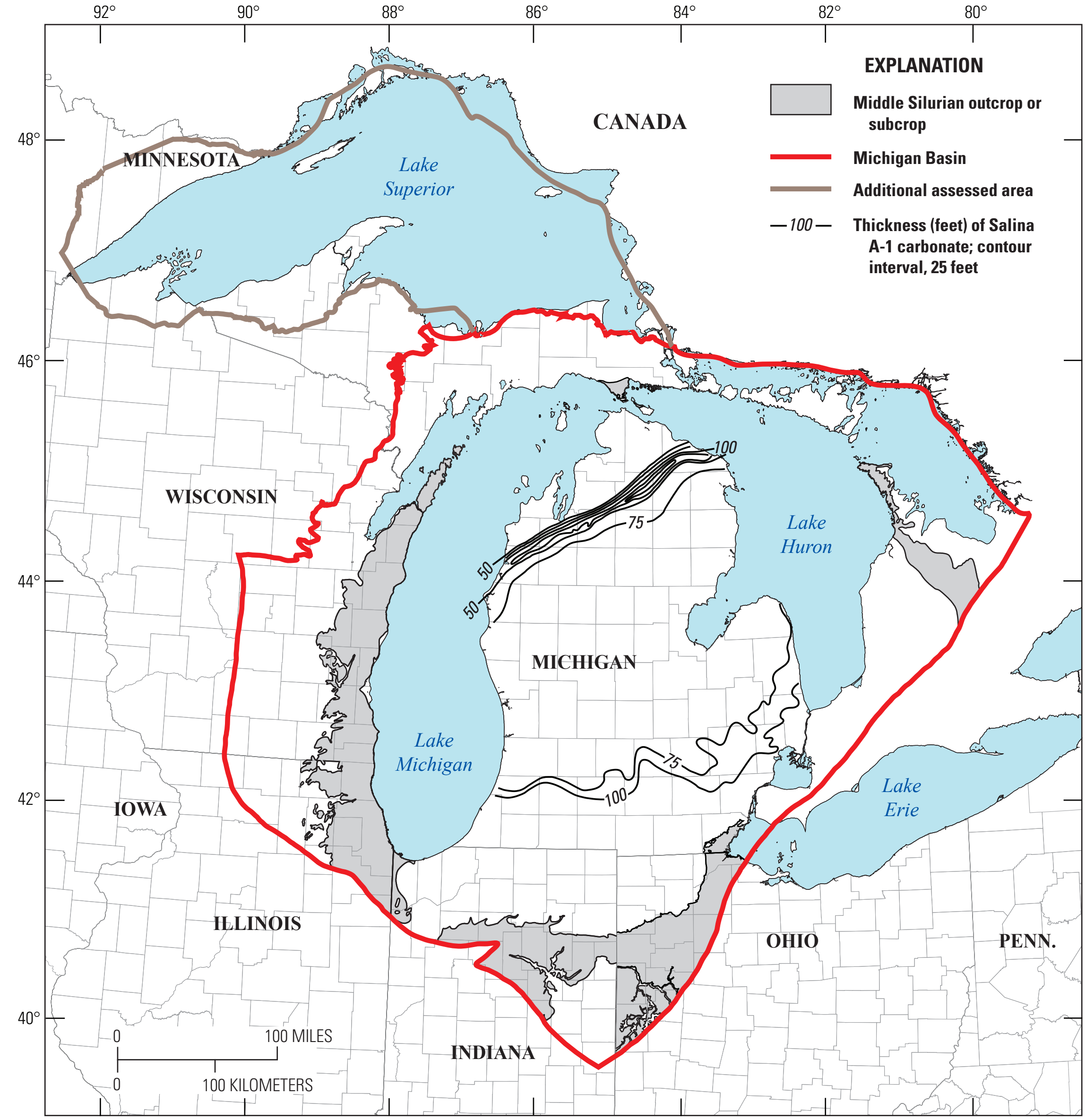
For the assessment calculations, a minimum grown field size of 0.5 MMBO equivalent was used for oil fields, and a minimum grown field size of 3 BCFG of gas was used for gas fields. As of 2004, the Silurian A-1 Carbonate AU contained no known oil fields and one known gas field with grown field size exceeding the minimum size. Also, as of 2004, the combined Salina A-1 carbonate and Salina A-2 carbonate were estimated to have produced a cumulative of 5 MMBO and 20 BCFG in Michigan (figs. 9 and 10); the majority of this production is from the Salina A-1 carbonate. The numbers of undiscovered gas accumulations greater than the minimum grown field size were estimated as follows: minimum = 1 gas accumulation, mode = 6 gas accumulations and maximum = 40 gas accumulations. The sizes of undiscovered gas accumulations greater than the minimum grown field size were estimated as follows: minimum = 3 BCFG, median = 6 BCFG and maximum = 25 BCFG.

Devonian Sylvania Sandstone Assessment Unit

The Devonian Sylvania Sandstone AU consists of the Middle Devonian Sylvania Sandstone. The thickness of the Sylvania Sandstone and correlative strata (fig. 75) ranges from about 50 to 200 ft throughout most of its extent, and elevations at the top of the Sylvania Sandstone (fig. 76) range from about 400 ft above sea level to 4,000 ft below sea level.

The Sylvania Sandstone is the basal formation of the Middle Devonian Detroit River Group. In some places the Sylvania Sandstone rests conformably on the Middle Devonian Bois Blanc Formation, but in other places the Sylvania Sandstone rests on an unconformity above the Upper Silurian Bass Islands Group. There is a gradational contact between Sylvania Sandstone and the overlying Middle Devonian Amherstburg Formation.

The Devonian Sylvania Sandstone consists of sandstone that grades laterally to the west and north into carbonate micrite and cherty dolomite (fig. 75). In most places, the Sylvania Sandstone is a white, quartz sandstone with dolomitic cement, secondary quartz overgrowths, and interbedded carbonate strata (Carman, 1936; Landes, 1945, 1951; Gardner, 1974; Catacosinos and others, 1990). Grain size decreases toward the northwest. The fauna in the Sylvania Sandstone is similar to that of the Detroit River Group but is quite different from the fauna in the Bass Islands Group. Fossils in the Sylvania Sandstone include abundant brachiopods (*Prosserella*, *Rhipidomella*). Sedimentary structures and textures include northwest-inclined cross beds, planar to irregular beds, and desiccation cracks.



The base map for this figure is from Nicholson and others (2004).

Figure 70. Map of isopachs of the informal Upper Silurian Salina A-1 carbonate (also called Ruff Formation) of Salina Group in the central part of the Michigan Basin (from Mesolella and others, 1974).

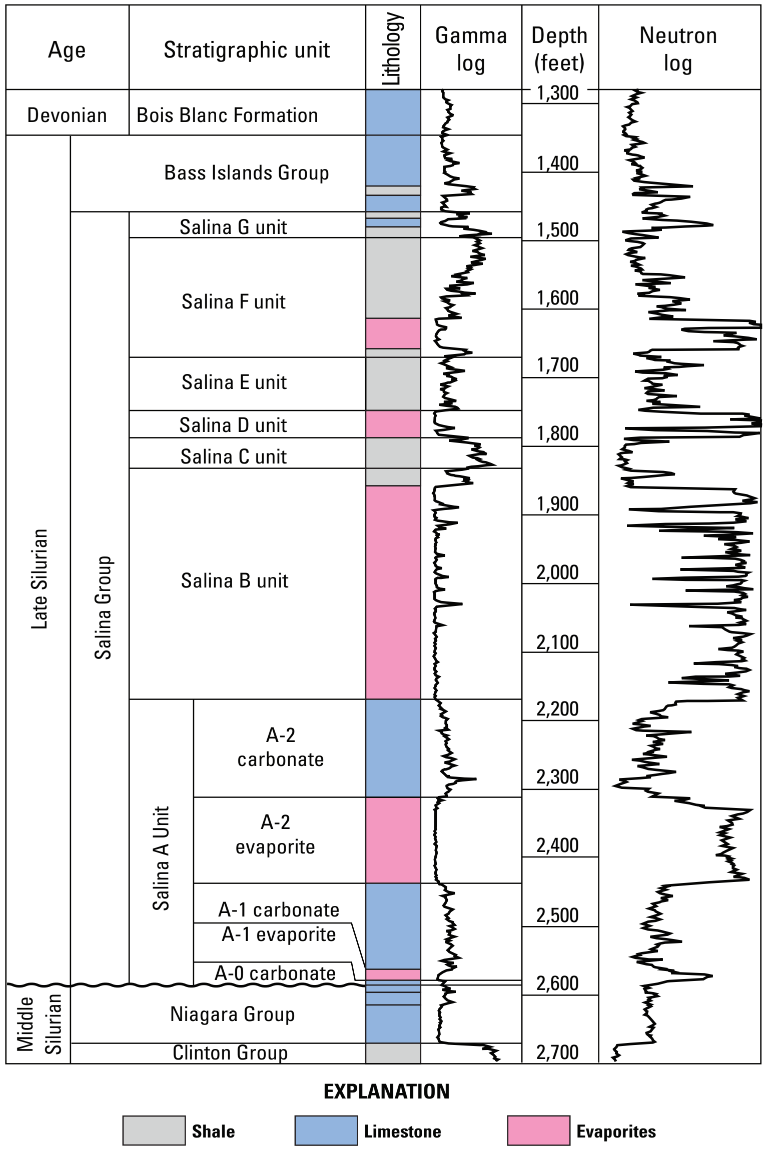


Figure 71. Upper Silurian Salina Group stratigraphy in the Michigan Consolidated Gas Company Carleton and others No. 1 well in the Belle River Mills field, southeastern Michigan (modified from Gill, 1977b). Location of field is shown in figure 58. Scales for gamma log and neutron log are not given.

Assessment Unit Model

The Devonian Sylvania Sandstone AU contains conventional petroleum accumulations. In the Canadian portion of the eastern part of the Michigan Basin, source rocks for petroleum in the Niagara and Salina Groups have been identified in the Eramosa Formation (an interreef facies of the Niagara Group) and the Salina A-1 Carbonate (within the Salina Group) (Powell and others, 1984; Obermajer and others, 2000). Although not yet verified, the assumption is that equivalent stratigraphic intervals in the U.S. part of the Michigan Basin are the source rocks for petroleum found in the Devonian Sylvania Sandstone AU. Some petroleum generation may have occurred during the Late Devonian (coincident with the Acadian orogeny) when the Niagara Group and Salina Group petroleum source rocks may have entered the oil window in the deepest part of the basin (Hayba, 2005). Subsequently, during the Pennsylvanian and Permian (coincident with the Alleghanian orogeny), most of the Niagara Group and Salina Group source rocks in the central part of the basin entered the gas window and continued to generate petroleum. Today, parts of the Niagara and Salina Groups are within the gas window in the central part of the basin (fig. 50). Along the northern and southern reef trends, however, most of the Niagara and Salina strata are within the oil window.

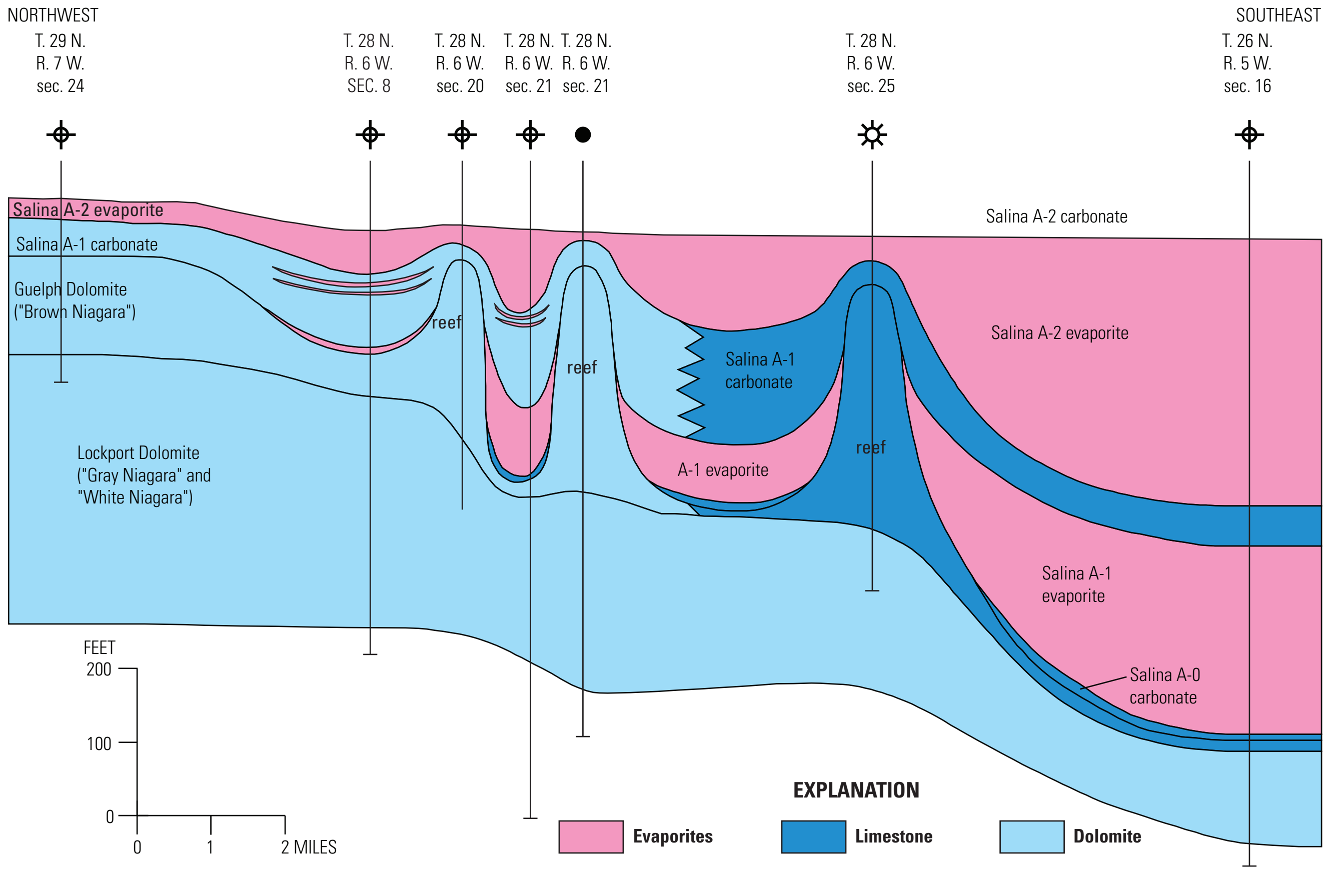


Figure 72. Cross section through the Middle Silurian Niagara Group and Upper Silurian Salina Group in Antrim and Kalkaska Counties, in northern Michigan (from Huh and others, 1977). Line of cross section is shown in figure 58. Brown, Gray, and White Niagara are informal units of the Niagara Group.

Reservoir Characteristics

As of the 2004 assessment, petroleum had not been produced commercially from the Devonian Sylvania Sandstone AU, although sandstone within the assessment interval is a potential reservoir rock. The Sylvania Sandstone has good porosity, good permeability, and minimal cement, and several shows of oil and gas have been reported from the formation in southeastern Michigan (Landes, 1945). Throughout some of its extent, however, the Sylvania Sandstone is an aquifer and may not be a good candidate for petroleum reservoirs. The reservoirs in the Devonian Sylvania Sandstone AU are probably stratigraphic traps associated with decreases in porosity and sandstone pinchouts into carbonate micrite (Bois Blanc Formation). The overlying Amherstburg Formation (carbonate wackestone) could act as a reservoir seal, and the laterally adjacent carbonate micrite could also act as a reservoir seal.

Petroleum Geochemistry

The chemical compositions (N_2 mole percent, CO_2 mole percent, H_2S mole percent, ethane/isobutane mole percent/mole percent, and gas wetness percent) of three natural gas samples from the strata that are laterally equivalent to the Sylvania Sandstone are summarized in table 9. Two of these samples are from Cass County, in southwestern Michigan (which does not contain Sylvania equivalent strata, as shown on fig. 75), and the third sample is from Kalamazoo County, Michigan (both county locations shown on fig. 76). The data summarized in table 9 are from Moore and Sigler (1987), Hamak and Sigler (1991), and data listed in Michigan Oil and Gas Well Gas Analyses Data from the Michigan Geological Repository for Research and Education at Western Michigan University (http://wsh060.westhills.wmich.edu/MGRRE/data/).

In some of these data files, the producing zone in these wells is called "Sylvania," but the lithology is dolomite and anhydrite rather than sandstone. Reservoir depths for these samples range from 968 to 1,645 ft. Based on the (1) limited number of natural gas analyses (n = 3) from the Sylvania Sandstone and equivalent strata, (2) limited geographic distribution of the samples, and (3) uncertainty of the stratigraphic intervals sampled, meaningful comparison of the gas analyses summarized in table 9 with any other set of gas analyses is not advised.

The base map for this figure is from Nicholson and others (2004).

Figure 73. Map of isopachs of the Upper Silurian A-2 evaporite (Salina Group) in the central part of the Michigan Basin (from Mesolella and others, 1974).

The base map for this figure is from Nicholson and others (2004).

Figure 74. Map showing locations of oil and gas fields where production is from reservoirs in the Silurian A-1 Carbonate Assessment Unit (AU) in the U.S. portion of the Michigan Basin (from U.S. Geological Survey Web site http://energy.cr.usgs.gov/oilgas/noga). Os, Oscoda County; Tu, Tuscola County.

Table 8. Statistical summary of the chemical compositions of 11 natural gas samples collected from wells producing from off-reef reservoirs in the informal Upper Silurian A-1 and A-2 carbonates in Oscoda County (10 samples) and Tuscola County (1 sample) in eastern Michigan.

[*Wetness (percent) = 100 × (1− [C1 mole percent/ΣC1–C5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	11	11	11	11	11
Median	0.23	8.0	0.50	4.2	13
Average, Standard deviation	0.59 ± 0.47	4.3 ± 4.2	0.36 ± 0.35	4.6 ± 2.2	16 ± 4.5
Range	0.20–1.21	0.31–9.3	<0.01–0.75	2.6–7.8	12–22

Undiscovered Petroleum Resources

In the 2004 assessment of the U.S. portion of the Michigan Basin, the USGS assessed the Devonian Sylvania AU as a conventional petroleum accumulation. The assessment unit was considered to be primarily gas-prone, and the undiscovered fields were estimated to include only gas fields. For the gas fields, the estimated volumes of undiscovered, technically recoverable natural gas resources are 0.0 BCGF at the 95-percent certainty level, 10.7 BCFG at the 50-percent certainty level, 23.9 BCFG at the 5-percent certainty level, and a mean of 10.3 BCFG. For natural gas liquids, the estimated volumes are 0.0 MMBNGL at the 95-percent certainty level, 0.7 MMBNGL at the 50-percent certainty level, 1.6 MMBNGL at the 5-percent certainty level, and a mean of 0.7 MMBNGL (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).

For the assessment calculations, a minimum grown field size of 0.5 MMBO equivalent was used for oil fields, and a minimum grown field size of 3 BCFG was used for gas fields. As of 2004, the Devonian Sylvania Sandstone AU contained no known oil fields and one known gas field with grown field size exceeding the minimum size. Also as of 2004, the assessment unit was estimated to have produced a cumulative of 0.2 MMBO and 0.1 BCFG (figs. 9 and 10), although the reliability of these estimates is uncertain. The numbers of undiscovered accumulations greater than the minimum grown field size were estimated as follows: minimum = 1 gas accumulation, mode = 2 gas accumulations, and maximum = 5 gas accumulations. The sizes of undiscovered accumulations greater than the minimum grown field size were estimated as follows: minimum = 3 BCFG, median = 5 BCFG and maximum = 20 BCFG.

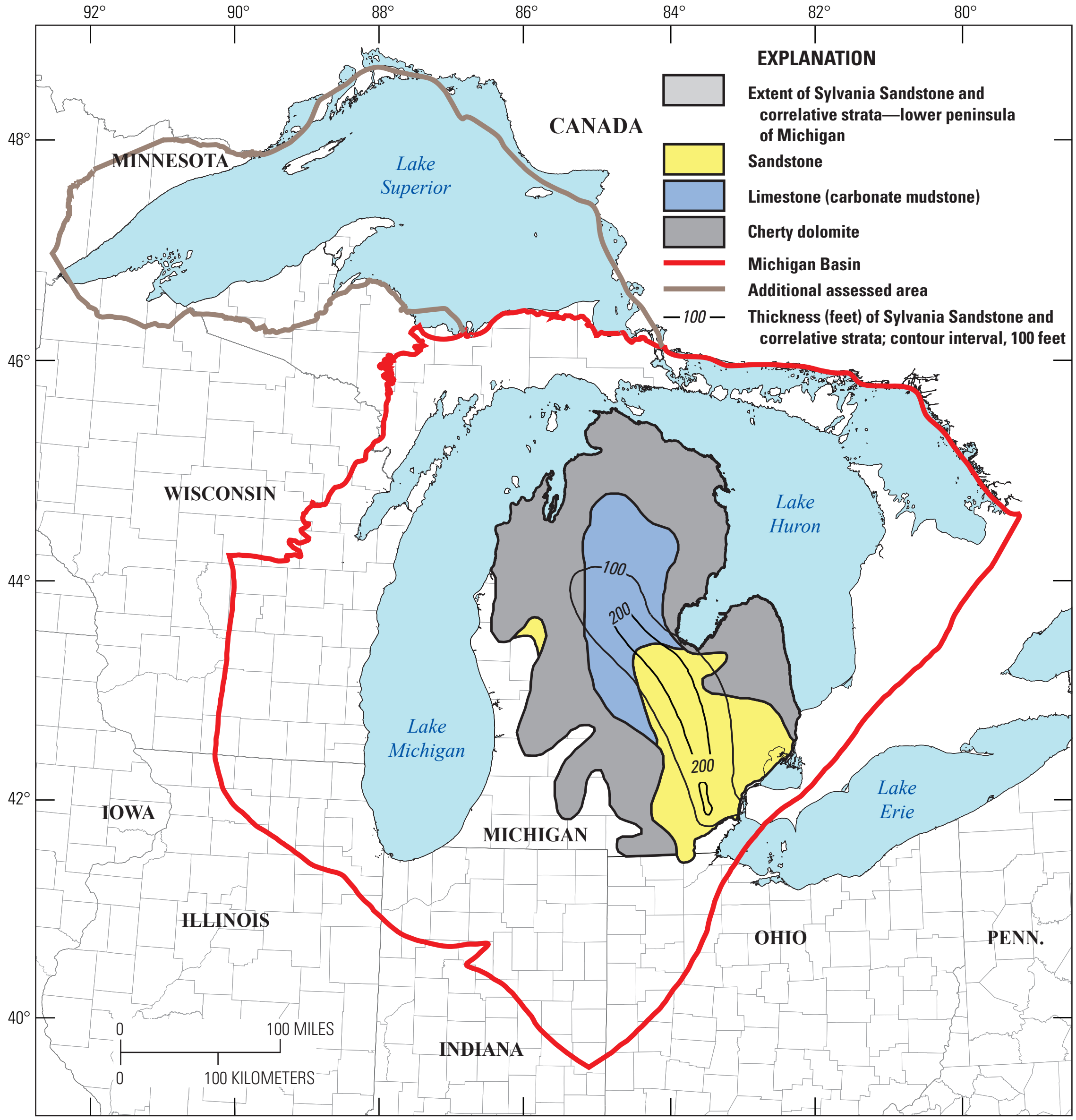
Ordovician to Devonian Composite Total Petroleum System—Part II

The Ordovician to Devonian Composite TPS is based on the presence of three different petroleum source-rock intervals and evidence for significant vertical petroleum migration and mixing of petroleums (oils and natural gases) through much of the Ordovician through Devonian stratigraphic section. The three petroleum source-rock intervals are (1) Middle Ordovician Trenton Formation and Middle Ordovician Collingwood Shale, (2) Middle Devonian Detroit River Group (Amherstburg Formation and Lucas Formation), and (3) Upper Devonian Antrim Shale (fig. 5). Part II of the Ordovician to Devonian Composite TPS focuses on the Middle Devonian part of this total petroleum system because various mixtures of petroleum from all three source-rock intervals can be identified in Middle Devonian reservoirs.

In Part II, petroleum source rocks within the Middle Devonian Detroit River Group (Amherstburg and Lucas Formations) are characterized. Part II also presents geochemical analyses of petroleum produced from Middle Devonian reservoirs that show commingling of petroleums (oils and natural gases) originating within the Detroit River Group, with petroleums originating in other source-rock intervals in the Trenton Formation and (or) Collingwood Shale lower in the section. Part II also provides oil analyses that show the sources of petroleum in reservoirs in the Middle Devonian Traverse Group are from the overlying Upper Devonian Antrim Shale. Petroleum source rocks in the Antrim Shale are characterized in the section Ordovician to Devonian Composite TPS—Part III. In Part II, one assessment unit, the Middle Devonian Carbonates AU, is described, and the undiscovered petroleum resources assessed.

Middle Devonian Petroleum Source Rocks

Within the Detroit River Group, two formations, the Amherstburg and Lucas Formations, are the apparent sources for most of the petroleum associated with the Middle Devonian Carbonates AU. The Amherstburg Formation gradationally overlies the Sylvania Sandstone and the Blois Blanc Formation (where the Sylvania Sandstone is absent). The Amherstburg Formation is overlain by the Lucas Formation, which in turn is gradationally overlain by the Middle Devonian Dundee Limestone. In the upper part of the Amherstburg



The base map for this figure is from Nicholson and others (2004).

Figure 75. Map of isopachs and predominant lithologies of the Middle Devonian Sylvania Sandstone and correlative strata in the central part of the Michigan Basin (modified from Landes, 1945; Catacosinos and others, 1990).

The base map for this figure is from Nicholson and others (2004).

Figure 76. Structure map on the top of the Devonian Sylvania Sandstone Assessment Unit (shaded area) in the central part of the Michigan Basin (after Landes, 1945). This map is also a structure map on the base of the Middle Devonian Detroit River Group. Ca, Cass County; Ka, Kalamazoo County.

Table 9. Statistical summary of the chemical compositions of three natural gas samples collected from wells producing from the Middle Devonian Sylvania Sandstone in Cass and Kalamazoo Counties in southwestern Michigan.

[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	3	3	3	3	3
Median	10.6	1.1	0.13	3.4	38
Average, Standard deviation	9.8 ± 2.9	0.96 ± 0.83	0.24 ± 0.30	5.4 ± 4.1	30 ± 18
Range	6.6–12	0.07–0.58	<0.01–0.58	2.6–10.1	9.7–44

Formation is a black limestone, which is mapped as the Meldrum Member (and is known informally as the “black lime” or “black limestone”). The Meldrum Member, a possible petroleum source rock, ranges to more than 300 ft thick in the central part of the Michigan Basin (fig. 77). Similarly, the upper part of the Lucas Formation contains dark, carbonate micrite, mapped as the Horner Member, which is also a possible petroleum source rock. The Horner Member ranges to more than 800 ft thick in the central part of the Michigan Basin (fig. 78).

There are very few analytical data regarding organic-matter-rich strata within the Middle Devonian carbonate rocks of the Michigan Basin. Snowdon (1984) lists organic-carbon contents for three Dundee Limestone samples from Ontario, Canada; unpublished USGS reports list organic-carbon contents for nine Amherstburg Formation and Dundee Limestone samples collected from cores primarily from Missaukee and Clare Counties, Michigan. The distribution of organic-carbon contents for these 12 samples is shown in figure 79. Although the organic matter in the nine Amherstburg Formation samples is thermally mature with respect to petroleum generation (Rock-Eval T_{max} >440 °C), the organic-carbon analyses have not been corrected for thermal maturity. With respect to organic matter thermal maturity and petroleum generation, both the Amherstburg and Lucas Formations are primarily within the oil-generation window (CAI = 1.5 to 2.5) in the central part of the Michigan Basin (fig. 80). Consequently, undiscovered petroleum resources in the Middle Devonian Carbonates AU would primarily consist of oil.

Middle Devonian Carbonates Assessment Unit

The Middle Devonian Carbonates AU consists primarily of limestone, dolomite, halite, and anhydrite. From base to top, the Middle Devonian Carbonates AU includes (1) the middle and upper stratigraphic intervals within Detroit River Group (Amherstburg and Lucas Formations), (2) the Dundee Limestone, and (3) the Middle Devonian Traverse Group. Stratigraphic contacts between most of the formations and members are gradational and (or) conformable. Elevations at the base of the Middle Devonian Carbonates AU (fig. 76) range from about 400 ft above sea level on the north margin of the basin to 4,500 ft below sea level in the center; elevations at the top of the Middle Devonian Carbonates AU (top of Traverse Group, fig. 81) range from about 400 ft above sea level to about 2,400 ft below sea level.

The Amherstburg Formation is primarily a gray-to-black, carbonate wackestone (Gardner, 1974; Catacosinos and others, 1990). Fossils include stromatoporoids, sponges (*Cladopora*), corals (including *Favosites*), brachiopods, and crinoids. Structures and textures in the formation include bioturbation and pelletal grains. In the center of the Michigan Basin, much of the Amherstburg Formation consists of dark fossiliferous limestone that is mapped as the Meldrum Member. The Meldrum Member is a dark-gray-brown to black bioturbated wackestone, with massive bedding to poorly developed bedding. Fossils include fragments of crinoids, corals, and brachiopods, as well as unbroken corals and stromatoporoids in growth positions. In western Michigan, the Meldrum Member of the Amherstburg Formation is overlain by and (or) interfingers with discontinuous and lenticular beds of sandstone (called the Filer Member of the Amherstburg Formation).

In the subsurface, the base of the Amherstburg Formation is placed at the top of the Sylvania Sandstone or at the top of the Bois Blanc Formation (cherty carbonate). The contact of the Amherstburg Formation with the overlying Lucas Formation (upper part of the Detroit River Group) is placed at the top of a coral-bearing limestone or at the base of brown to tan micritic dolomite. This contact, however, is gradational because there is some interbedding of dark coral-bearing limestone (Amherstburg Formation) with brown to tan micritic dolomite (Lucas Formation).

The Lucas Formation is composed primarily of micritic dolomite and anhydrite (Gardner, 1974; Catacosinos and others, 1990). Throughout much of the basin, the Lucas Formation consists of three members (from base to top): Richfield, Iutzi, and Horner Members.

1. The Richfield Member (lowermost member of the Lucas Formation) ranges in thickness from 0 to 200 ft throughout much of its extent (fig. 82) and is a tan to brown

The base map for this figure is from Nicholson and others (2004).

Figure 77. Map of isopachs of the Middle Devonian Meldrum Member of the Amherstburg Formation (Detroit River Group) in the central part of the Michigan Basin (after Gardner, 1974).

The base map for this figure is from Nicholson and others (2004).

Figure 78. Map of isopachs of the Middle Devonian Horner Member of the Lucas Formation (Detroit River Group) in the central part of the Michigan Basin (after Gardner, 1974).

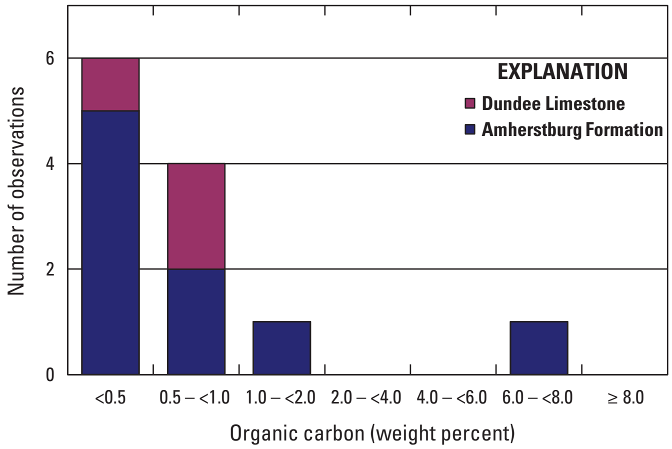


Figure 79. Histogram showing the distribution of organic-carbon contents (in weight percent) for 12 samples from the Middle Devonian Amherstburg Formation and Dundee Limestone. Analyses of the Dundee Limestone samples are from southern Ontario, Canada (Snowdon, 1984); analyses of the Amherstburg Formation samples are unpublished U.S. Geological Survey data.

micritic dolomite with beds of anhydrite. Fossils include brachiopods (*Prosserella*), algal laminae, and stromatolites. Structures and textures include oolites, crossbedding, ripple marks, laminations, mud cracks, and nodular-mosaic anhydrite. There are two intervals of anhydrite beds; the stratigraphically lower beds are less extensive than those higher in the section. Along the northwest margin of the basin, the micritic dolomite is sandy and contains a few discontinuous lenses of sandstone (for example, the informal “Richfield sandstone” and “Freer sandstone”). The Richfield Member is conformably overlain by the Iutzi Member, and the top contact of the Richfield Member is picked at the base of an anhydrite bed (informally called the “massive anhydrite”) in the Iutzi Member.

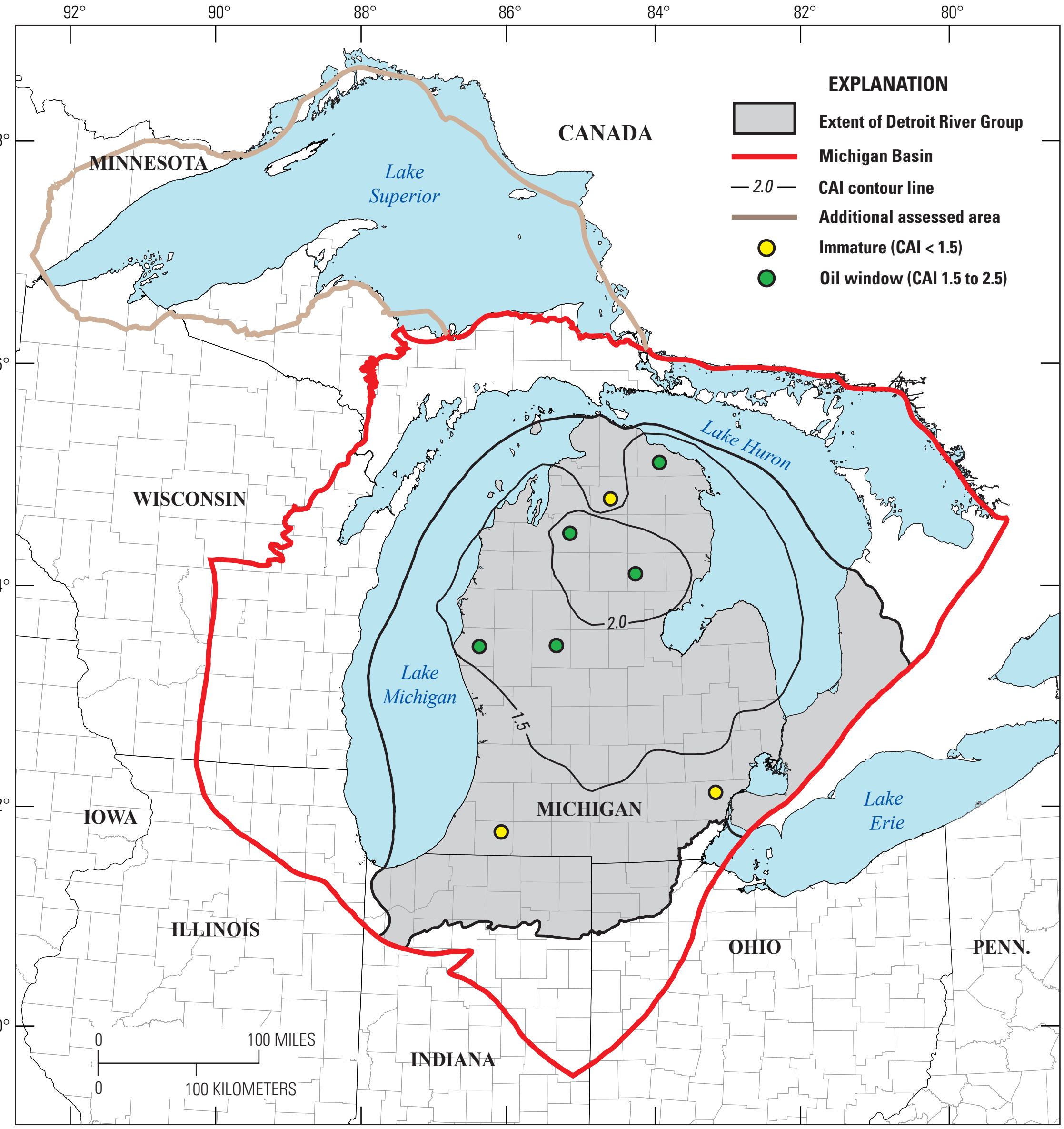
2. The Iutzi Member (middle member of the Lucas Formation) ranges in thickness from less than approximately 50 ft to almost 200 ft throughout much of its extent (fig. 83). This member consists of a lower interval of predominantly anhydrite (informally called the “massive anhydrite”) that is generally 75 to 100 ft thick and an upper interval of gray-brown carbonate and dolomitic anhydrite that ranges from 25 to 100 ft thick. The anhydrite beds become thinner and grade into dolomite on the basin margins.

3. The Horner Member (uppermost member of the Lucas Formation) ranges in thickness from 100 to 800 ft throughout much of its extent (fig. 78). It consists primarily of halite, with some beds of anhydrite and dark micritic carbonate. In the central part of the basin, the base of the Horner Member occurs at the base of the lowermost halite bed above the Iutzi Member. Structures and textures in the Horner Member include dolomitic anhydrite and layered anhydrite. One of the dark carbonate beds (informally named the “sour zone”) is a distinct fractured, dark-gray-brown micrite with gray-brown dolomitic anhydrite and a strong odor of hydrogen sulfide. In addition to the lithologies mentioned above, the Horner Member contains a biotite-bearing ash bed (the Kawkawlin Bentonite), which is considered to be equivalent to the Tioga Ash Bed of the Appalachian Basin (Baltrusaitis, 1974). The Horner Member of the Lucas Formation is overlain by the Dundee Limestone.

The contact between the Lucas Formation and the overlying Dundee Limestone is gradational. Within the productive trend of east-central Michigan where the Dundee Limestone is dolomite, Gardner (1974) picked the Lucas Formation-Dundee Limestone contact as the top of first anhydrite bed below the Dundee Limestone, whereas Curran and Hurley (1992) picked the contact as the top of the first pervasive dolomite bed below the Dundee Limestone. The Dundee Limestone has an informal lower member called the “Reed City member” (or “Reed City zone”) and an upper member called the Rogers City Member (or “Rogers City zone”).

The Dundee Limestone ranges in thickness from less than 100 ft in the western part of the basin to more than 400 ft in the east-central part of the basin (fig. 84). It is composed predominantly of buff to brown-gray crystalline limestone, except in the extreme western and southwestern part of Michigan where the Dundee Limestone is entirely dolomite (Gardner, 1974; Wilson, 1983; Curran and Hurley, 1992; Montgomery and others, 1998; Catacosinos and others, 1990; Myles, 2001). Dolomite is also present generally at the base of the formation. Where the Dundee Limestone is not dolomitized, it is a brown bioturbated wackestone to grainstone with brachiopods, tabulate and rugose corals, and crinoid fragments. Laminae of impure anhydrite and porous dolomite are present in the western and southwestern parts of the basin. In the west-central part of the basin, the Dundee Limestone is divided into (ascending) the informal Reed City member (or Reed City zone) and the Rogers City Member (or Rogers City zone). The Reed City member is a brown to gray massive dolomite and dolomitic limestone. The top of an anhydrite bed (the “Reed City anhydrite”) forms the contact between the Reed City member and the overlying Rogers City Member, although the anhydrite bed is absent in the eastern half of the basin. The Rogers City Member is a massive limestone throughout the basin, except where it is dolomitized in the west (where the underlying Reed City is also dolomite and the Reed City anhydrite is discontinuous). The Rogers City Member is dark brown in the basin center and has a lighter color on the basin margins. Elevations at the top of the Dundee Limestone (fig. 85) range from about 400 ft above sea level to about 3,000 ft below sea level. The Dundee Limestone (Rogers City Member) is overlain by the Traverse Group.

As shown in figure 5, the Traverse Group is divided into two units, the Bell Shale and the Traverse limestone. There are four stratigraphic units in the Traverse Group: from base to top they are the Bell Shale, Rockport Quarry Limestone, Ferron



The base map for this figure is from Nicholson and others (2004).

Figure 80. Map showing the thermal maturity of organic matter in the Middle Devonian Amherstburg and Lucas Formations (both Detroit River Group) in the central part of the Michigan Basin based on conodont color alteration index (CAI). Contours are based on limited data. With respect to petroleum generation, CAI values <1.5 = immature; CAI from 1.5 to 2.5 = oil window.

The base map for this figure is from Nicholson and others (2004).

Figure 81. Structure map on the top of the Middle Devonian Traverse Group in the central part of the Michigan Basin (after Wylie and Huntoon, 2003). Outcrop and subcrop areas of the Traverse Group are shown in darker blue.

The base map for this figure is from Nicholson and others (2004).

Figure 82. Map of isopachs of the Middle Devonian Richfield Member of the Lucas Formation (Detroit River Group) in the central part of the Michigan Basin (after Gardner, 1974).

The base map for this figure is from Nicholson and others (2004).

Figure 83. Map of isopachs of the Middle Devonian Iutzi Member of the Lucas Formation (Detroit River Group) in the central part of the Michigan Basin (after Gardner, 1974).

The base map for this figure is from Nicholson and others (2004).

Figure 84. Map of isopachs of the Middle Devonian Dundee Limestone in the central part of the Michigan Basin (after Gardner, 1974).

The base map for this figure is from Nicholson and others (2004).

Figure 85. Structure map on the top of the Middle Devonian Dundee Limestone in the central part of the Michigan Basin (after Wylie and Wood, 2005).

Point Formation and Thunder Bay Limestone (Catacosinos and others, 2001). In the subsurface, the three (primarily limestone) units above the Bell Shale, collectively, are informally called the Traverse limestone. In the following paragraphs, when discussing the subsurface petroleum geology, Traverse limestone will be used when referring to the limestone interval above the Bell Shale.

The Traverse Group ranges in thickness from less than 200 ft in southern Michigan to more than 800 ft in northeastern Michigan (fig. 86) and consists of carbonate strata that interfinger to the east with shale that is equivalent to the Hamilton Group in Ontario (Gardner, 1974; Wilson, 1983; Catacosinos and others, 1990). The Traverse Group progressively onlaps the underlying Dundee Limestone and Lucas Formation from northeast to southwest. The percentage of shale within the Traverse Group reaches a maximum of 80 percent in the vicinity of Saginaw Bay and decreases to about 20 percent throughout most of the rest of the basin. Elevations at the top of the Traverse Group (fig. 81) range from 400 ft above sea level to 2,500 ft below sea level; the Traverse Group outcrops in northern Michigan. In southeastern Michigan, there is an erosional unconformity between the Traverse Group and the Antrim Shale.

The Bell Shale is gray-green shale, about 80 ft thick throughout much of the basin, but pinches out to the southwest. The contact of the Bell Shale with underlying strata is conformable in the basin center and disconformable on the basin margins. In the subsurface, the Bell Shale is conformably overlain by the Traverse limestone, which contains many carbonate lithologies including biostromes and bioherms (as much as 35 ft thick) of coral and stromatoporoids, as well as beds containing fragments of brachiopods, bryozoa, and crinoids. In the western part of the basin, the Traverse limestone contains beds of dolomite, chert, and anhydrite. In the eastern part of the basin, the Traverse limestone contains beds of gray fossiliferous shale.

The Traverse Group is overlain by the Squaw Bay Limestone (which is equivalent to the Traverse Formation of Gutschick and Sandberg, 1991a,b). The Squaw Bay Limestone is gray limestone (wackestone to grainstone) and shaly limestone, with interbedded gray and black shales that progressively dominate the section upward. It is a transitional unit to the overlying Antrim Shale. It is as much as 80 ft thick in the western and central portions of Michigan and thins to a featheredge in eastern Michigan (Catacosinos and others, 2001). Fossils include tabulate and rugose corals, crinoids, brachiopods, bryozoa, and trilobites.

Assessment Unit Model

The Middle Devonian Carbonates AU contains conventional petroleum accumulations. The petroleum source rocks include the Middle Ordovician Trenton Formation and Collingwood Shale, the Middle Devonian Amherstburg and Lucas Formations (both of the Detroit River Group), and the Upper Devonian Antrim Shale. Petroleum generation began to occur during the Late Devonian (coincident with the Acadian orogeny), when the Collingwood Shale and thin shale beds in the upper part of the Trenton Formation entered the oil window in the deepest part of the basin (Hayba, 2005). Subsequently, during the Pennsylvanian and Permian (coincident with the Alleghanian orogeny), most of the Collingwood Shale and shale beds in the upper part of the Trenton Formation entered the gas window and the Amherstburg and Lucas Formations (Detroit River Group) entered the oil window. In addition, it is likely that the Antrim Shale entered the oil window during the Pennsylvanian and Permian in the deepest part of the basin.

According to Prouty (1988), replacement dolomite, saddle dolomite (baroque dolomite), and petroleum occur in all of the major carbonate reservoirs of the Michigan Basin (Trenton and Black River Formations, Detroit River Group, Dundee Limestone, and Traverse Group). There is some debate, however, about the timing of dolomitization and petroleum migration. Evidence from the Reed City field suggests the following sequence of events (Carlton and Prouty, 1983): (1) pre-Dundee shear faulting and folding, (2) post-Traverse Group upward migration of dolomitizing fluids, (3) upward migration of petroleum along the shear faults, (4) downward migration of dedolomitizing fluids, and (5) a later episode of faulting, especially shear cross-faults. In another publication, Prouty (1988) suggests that the petroleum migration route was upward along faults, and he postulates that petroleum entrapment occurred during the Early Mississippian. Middleton and others (1993), however, postulate that the movement of the fluids that caused the fracture-related dolomitization may be associated with the Pennsylvanian and Permian Alleghanian orogeny. A Permian age for petroleum migration is also supported by data from the Stoney Point field, where the Trenton and Black River Formations exhibit strong magnetic signatures consisting of a modern geomagnetic-field direction and a Late Permian geomagnetic-field direction (Suk and others, 1993). Subsequent work by Hayba (2005, 2006) indicates that the heat flux in the southeastern portion of the Michigan Basin was anomalously high during the time of maximum burial (Pennsylvanian and Permian), and this anomalous heat flux is attributed to topographically driven fluid migration from the Appalachian Basin, across the Findlay arch, and into the southeastern part of the Michigan Basin (Hayba, 2005, 2006; Rowan and others, 2007, 2008).

Regardless of the timing of migration, the presence of petroleum in Devonian reservoirs derived from Ordovician source rocks requires at least one episode of petroleum leakage from the Ordovician source rocks, through evaporite beds of the Silurian Salina Group, and into the Devonian carbonate strata (Hatch and others, 2005). The concept that petroleum in Middle Devonian carbonate reservoirs overlying the Salina evaporite beds in the central part of the Michigan Basin is derived (at least in part) from Ordovician source rocks is supported by the three observations: (1) the saturated hydrocarbon distributions of these oils are dominated by the geochemical signature of *Gloeocapsamorpha prisca* (an organic-walled microfossil of Cambrian and Ordovician age) (Jacobson and others, 1988; see figure 40 for an example of this saturated hydrocarbon distribution); (2) many of the oil reservoirs in the central part of the Michigan Basin (both above and below the

The base map for this figure is from Nicholson and others (2004).

Figure 86. Map of isopachs of the Middle Devonian Traverse Group in the central part of the Michigan Basin (after Wylie and Huntoon, 2003). Outcrop and subcrop areas of the Traverse Group are shown in darker blue.

Salina evaporite beds) are located along northwest-trending fractures, which are interpreted as flower structures controlled by reactivated deep basement faults; and (3) in Ordovician and Devonian carbonate reservoirs, some of these northwest-trending fractures are associated with minerals that are typical of hydrothermal fluid flow (for example, baroque dolomite, barite, fluorite, galena, and sphalerite). These minerals occurrences are more common in Ordovician age rocks.

Reservoir Characteristics

Reservoirs in the Middle Devonian Carbonates AU have produced both oil and gas (fig. 87). Lucas Formation production has been both oil and gas; Dundee Limestone and Traverse limestone production has been primarily oil. In many instances, any associated gas from this production was flared. In addition, some minor petroleum production has been established from the Amherstburg Formation in Ogemaw and Missaukee Counties (Catacosinos and others, 1990). Most petroleum traps in the Middle Devonian Carbonates AU are stratigraphic traps associated with anticlines. In the Lucas Formation, most production is either from porosity (intercrystalline or moldic) in dolomitized carbonate on structural highs or from stratigraphic pinchouts of carbonate into anhydrite (Catacosinos and others, 1990). In the Dundee Limestone and Traverse limestone, most reservoirs are associated with anticlines, and the extent of producing areas is limited by porosity, permeability, and edge-water (Davis, 1952; Cohee and Landes, 1958; Wilson, 1983; Catacosinos and others, 1990). It is thought that many of these anticlines formed during the Late Mississippian or later (Pirtle, 1932; Dorr and Eschman, 1970; Prouty, 1988; Curran and Hurley, 1992). At least some of the anticlines (for example, West Branch field and Clayton field; fig. 87) are associated with strike-slip movement on faults in the Precambrian basement. This strike-slip movement is basement-induced wrench faulting that has caused “tulip” structures in lower Paleozoic rocks below the Salina Group (Versical, 1990; Hatch and others, 2005).

Reservoir seals in the Middle Devonian Carbonates AU are beds of evaporites, shale, and low-porosity limestone. Anhydrite and halite beds provide reservoir seals in the Lucas Formation, whereas shale in the Squaw Bay Limestone and in the Antrim Shale may act as reservoir seals in the Traverse limestone.

Lucas Formation

Oil and gas have been produced from several stratigraphic intervals in the Lucas Formation (Cohee and Landes, 1958; Gardner, 1974; Knapp, 1979; Harrison, 1989; Catacosinos and others, 1990). Most production has been oil from dolomite beds in the Richfield Member (lowest member of the Lucas Formation). In the Richfield Member, the production of brine has been very limited, and an effective water drive is apparently absent. In addition to the Richfield Member, oil has been produced from the “sour zone” carbonate within the Horner Member (uppermost member of the Lucas Formation). Examples of specific fields in the Lucas Formation include the Enterprise field and Beaver Creek fields. These two fields are located on figure 87 and described below.

1. The Enterprise field (Missaukee County, Michigan) is located on a northwest-trending anticline and has primarily produced oil (Matzkanin and others, 1977). The field was discovered in 1943 and was developed on 40-acre spacing. The field contains several pay zones in the Richfield Member of the Lucas Formation. These pay zones consist of nine beds of dolomite separated by thin beds of anhydrite and limestone. Within the pay zones, average porosity is approximately 15 percent and average permeability is approximately 3.5 md. The net oil-pay thickness is approximately 16 ft, and solution gas is the reservoir-drive mechanism.

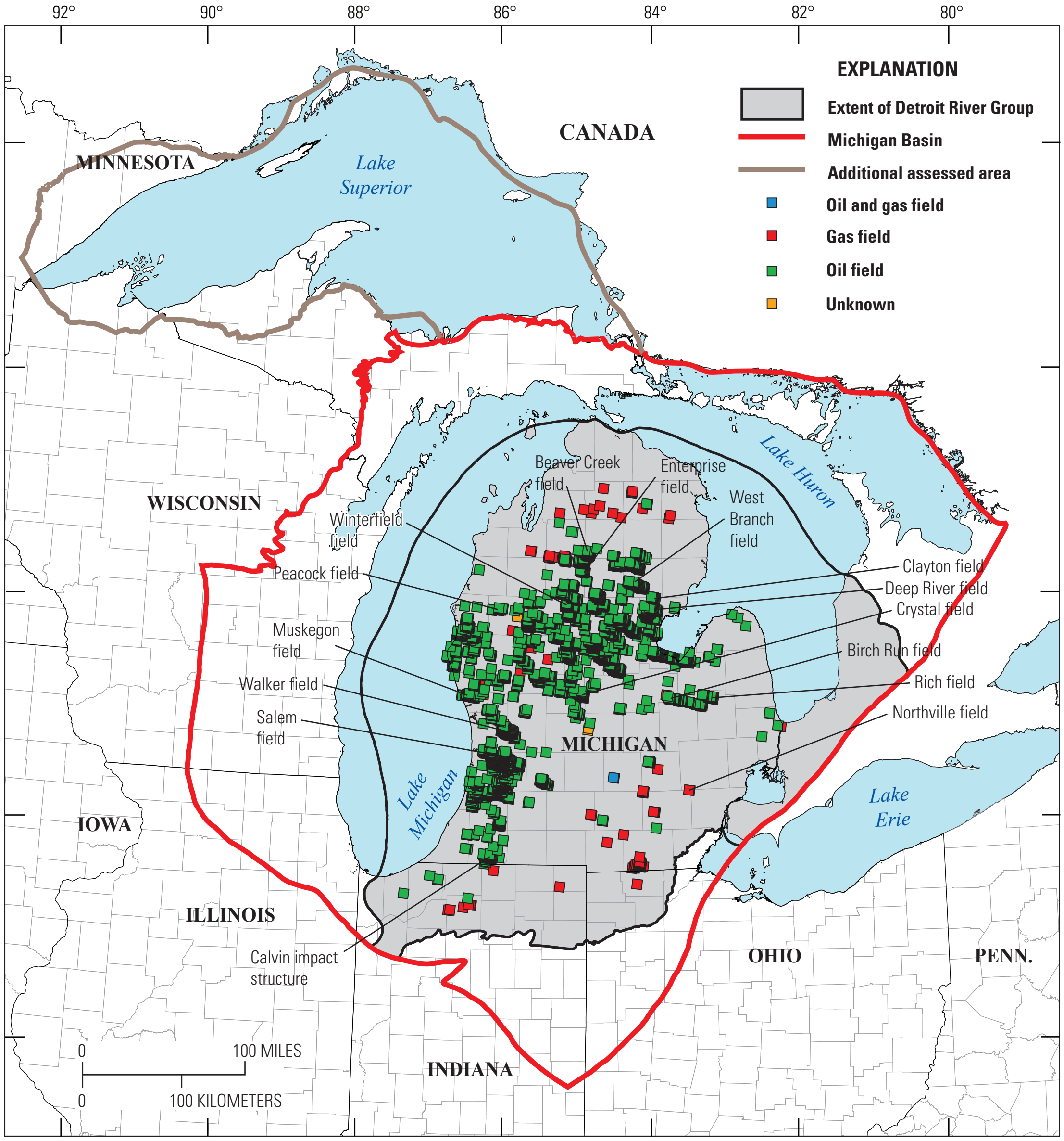
2. The Beaver Creek field (Crawford and Kalkaska Counties, Michigan) is also located on a northwest-trending anticline; the field has predominantly produced oil with some gas (Pollom and others, 1976). The field was discovered in 1947 and was developed on 40-acre spacing. The field contains several pay zones in the Richfield Member. These pay zones, which are located at depths ranging from 4,400 to 4,600 ft, consist of five or six beds of dolomite separated by thin beds of anhydrite and limestone. Within the pay zones, porosity ranges from 0 to 25 percent (average 15 percent), and average permeability ranges from 0 to 19 md. The net oil-pay thickness is approximately 17 ft. In most of the pay zones, solution gas is the reservoir-drive mechanism. In the southeast portion of the field, however, one reservoir interval has a small gas cap and gas-cap expansion is the reservoir-drive mechanism.

Dundee Limestone

Dundee Limestone petroleum production consists primarily of oil, although some gas is present in places. Most production from the Dundee Limestone is associated with anticlines, and the extent of producing areas is limited by porosity, permeability, and edge-water (Cohee and Landes, 1958). In general, three productive trends have been delineated within the Dundee Limestone (Knapp, 1979; Catacosinos and others, 1990; Montgomery and others, 1998; Barnes and Harrison, 2001; Harrison, 2001; Myles, 2001):

1. In the western part of the basin, oil is produced from stromatolitic and fenestral dolomite in the Reed City member of the Dundee Limestone. In this area, Dundee reservoirs consist of fenestral-fabric carbonate strata (interpreted as shallow-water deposits), with some minor patch reefs. Most production is from porous beds that have been pervasively dolomitized (sucrosic dolomite), and the porosity is predominantly moldic and intercrystalline. These reservoirs are generally associated with anticlines.

2. In the central and northern part of the basin, oil is produced from stromatolitic and fenestral dolomite, mostly in areas where the Reed City anhydrite is absent and where



The base map for this figure is from Nicholson and others (2004).

Figure 87. Map showing the locations of oil and gas fields where production is from reservoirs in the Middle Devonian Carbonates Assessment Unit in the U.S. portion of the Michigan Basin (from U.S. Geological Survey Web site http://energy.cr.usgs.gov/oilgas/noga). Identified fields are discussed in the text. Ms, Missaukee County; Og, Ogemaw County.

the Rogers City Member is dolomitized. In this area, Dundee reservoirs are localized in linear pods (from 2 to 20 ft thick) of fractured dolomite within tight limestone. Most production is from fractured, vug-bearing dolomite with solution-enhanced matrix porosity. The fracture porosity is thought to have been caused by wrenching associated with the reactivation of basement faults by late Paleozoic compression. Many Dundee reservoirs in the central part of the basin are also associated with subtle, northwest-trending anticlines that continue at depth to at least the Middle Ordovician St. Peter Sandstone. These anticlines may be associated with faults.

3. In the eastern part of the basin, oil in the Dundee Limestone is produced from fenestral-fabric carbonate strata (interpreted as shallow-water deposits), with some minor patch reefs. Most production is from skeletal-peloidal grainstone, reef-related boundstone, and reef-flank skeletal sand. Some production is also from linear intervals of fractured dolomite within otherwise tight limestone. Most of these reservoirs are associated with anticlines.

Most oil production from the Dundee Limestone has been from dolomite in the upper 20 to 50 ft of the Reed City member (lower member) of the Dundee Limestone. In addition, the Rogers City Member (upper member) of the Dundee Limestone has produced both oil and gas from zones of secondary porosity in dolomite. In general, most dolomite reservoirs in the Dundee Limestone have initial production rates ranging from hundreds to thousands of barrels per day. Water production from wells is abundant indicating a water-drive mechanism; reservoir pressures drop little during production. In contrast, most limestone reservoirs in the Dundee Limestone have initial production rates ranging from tens to hundreds of barrels per day. Water production is generally low throughout the life of the field; the drive mechanism is gas solution/expansion. Reservoir pressures have declined continuously during production (Harrison, 2001). Examples of specific fields in the Dundee Limestone include Clayton, Crystal, Deep River, Northville, West Branch, and Winterfield fields. These six fields are located on figure 87 and described below.

1. The Clayton field is located in Ogemaw and Arenac Counties and has produced oil primarily from the Dundee Limestone, as well as from various underlying and overlying units (Hake, 1938; Addison, 1940; Griffith, 1991; Curran and Hurley, 1992). The field was discovered in 1936 and is located on a low-relief northwest-trending asymmetric anticline that dips more steeply to the north. The anticline is associated with strike-slip movement on a fault in the Precambrian basement, and this strike-slip movement has created “tulip” structures in lower Paleozoic strata below the Silurian Salina Group.

2. The Crystal field is located in Montcalm County and has produced oil from both the Traverse limestone and the underlying Dundee Limestone (Hake, 1938; Addison, 1940; Wood and others, 1996; Montgomery and others, 1998). The field was discovered in 1934 or 1935 and is developed on 10-acre spacing. The main pay zone includes the upper 15 ft of the Dundee Limestone; the pay zone is at depths less than 3,500 ft. The pay interval is a vuggy, coarsely crystalline fractured dolomite that occurs immediately below an impermeable limestone in the upper part of the formation. In places, however, this upper impermeable limestone is missing, and shale directly overlies fractured dolomite at the top of the Dundee Limestone. A significant portion of the irregularity of the upper surface of the Dundee Limestone may be related to karst dissolution and solution collapse. Within the pay zones, the net oil-pay thickness ranges from 4 to 43 ft. An oil-water contact is present in the field; water drive is the dominant reservoir-drive mechanism. Fractures and solution-enhanced porosities are present below the oil-water contact. The field has an unusual structure resulting from flowage and dissolution of underlying evaporites in the Detroit River Group.

3. The Deep River field is located in Arenac County and has produced oil from the St. Peter Sandstone, Dundee Limestone, and Berea Sandstone (Cohee and Landes, 1958; Lundy, 1968; Catacosinos, 1987; Budros and Johnson, 1990; Catacosinos and others, 1990). The Dundee Limestone reservoir is in northwest-trending fractured dolomite surrounded by low-permeability limestone. The field is similar to the Albion-Scipio field (Ordovician Trenton/Black River AU).

4. The Northville field is located in Washtenaw, Wayne, and Oakland Counties and has produced both oil and gas from a number of stratigraphic intervals (Prouty, 1988; Hurley and Budros, 1990; Budai and Wilson, 1991). The field started producing from the Silurian Salina and Niagara Groups in 1937, from the Devonian Dundee Limestone in 1948, and from the Ordovician Trenton and Black River Formations in 1954. The reservoir intervals are fractured dolomite surrounded by low-permeability limestone. In some parts of this field, there are fractures lined with dolomite cement, then filled with barite cement intergrown with calcite cement. The field is located on a northwest-trending anticline.

5. The West Branch field is located in Ogemaw County and has produced oil from various stratigraphic intervals (Hake, 1938; Addison, 1940; Vugrinovich and Matzkanin, 1981; Prouty, 1988; Curran and Hurley, 1992). The field was discovered in 1933 or 1934 and was developed on 10-acre spacing. Primary production is from three pay zones in the Dundee Limestone that are 20 to 30 ft thick and at depths ranging from 2,500 to 2,650 ft. Additional production was subsequently established from the Detroit River Group “sour zone,” Richfield Member of the Lucas Formation, Amherstburg Formation, St. Peter Sandstone, and Prairie du Chien Group. The main pay zones in the Dundee Limestone consist of lenticular beds of skeletal

grainstone and packstone with primary, interparticle porosity. These lenticular beds are overlain by micritic carbonate with high porosity (from 5 to 15 percent) and low permeability (0 to 1.0 md). Within the Dundee Limestone pay zones, average porosity is approximately 10 percent and average permeability is approximately 4 md. The net oil-pay thickness is approximately 28 ft and solution-gas drive is the reservoir-drive mechanism. The field is located on a northwest-trending asymmetric anticline that dips more steeply to the north. The anticline is associated with strike-slip movement on a fault in the Precambrian basement, and this strike-slip movement has created "tulip" structures in lower Paleozoic strata below the Silurian Salina Group.

6. The Winterfield field is located in Clare County and has produced oil and gas from various stratigraphic intervals (Landes, 1944; McCaslin, 1980; Harrison and others, 1993; Chittick and others, 1995). The field has produced gas at a depth of 1,700 ft and oil at a depth of 3,900 ft. Production from the Dundee Limestone in this field was established during the late 1930s. The field has also produced from the Richfield Member of the Lucas Formation (Detroit River Group), Traverse limestone, St. Peter Sandstone, and Prairie du Chien Group. Within the Dundee Limestone, the pay zones consist of porous, dolomitized "chimneys" that extend up into low-permeability limestone. These dolomite "chimneys" are less than 60 ft high and can be laterally discontinuous between wells on 40-acre spacing. The dolomite pay zones have good porosity and permeability. Within the dolomite pay zones, an oil-water contact is present and water drive is the reservoir-drive mechanism. Most production at the Winterfield field is on a northwest-trending anticline, but an isolated pocket of oil in the Dundee Limestone was discovered off-structure during the 1980s.

Traverse Limestone

Traverse limestone petroleum production consists primarily of oil, although some gas is present in some reservoirs (Knapp, 1979; Wilson, 1983; Harrison, 1989; Catacosinos and others, 1990). Most Traverse limestone petroleum production is from the southwest quadrant of Michigan where the Traverse limestone is predominantly carbonate rock. In this area, the petroleum production is concentrated in carbonate boundstone (patch reefs) and skeletal grainstone associated with small structural highs or monoclines caused by the dissolution of underlying Silurian evaporites. In central Michigan, Traverse limestone production is from localized pods of fractured dolomite surrounded by low-permeability micritic limestone. In eastern Michigan, however, the Traverse limestone is predominantly shale and does not produce petroleum. Examples of specific fields in the Traverse limestone include Muskegon, Salem, and Walker fields and fields associated with the Calvin impact structure. These fields are located on figure 87 and described below.

1. The Muskegon field, located in Muskegon County, has produced oil and gas from numerous stratigraphic intervals (Newcombe, 1932; Hake, 1938; Grant, 1948). The field was discovered in 1927 and reached peak production in 1927. Initially, some oil was discovered in the Upper Devonian Berea Sandstone and (or) equivalent strata, and gas was produced at a depth of 1,640 ft in the upper part of the Traverse Group. Later, oil was produced from two deeper sections in the Traverse Group: (1) a 20- to 30-ft-thick interval in the Alpena Limestone, which is a formation defined in outcrop in the upper part of the Traverse Group and (2) a deeper interval in the Traverse limestone below a bed of anhydrite. In 1928, oil and gas were discovered in the Dundee Limestone, just below the base of the Bell Shale. Later, gas was discovered in the underlying Detroit River Group. In this field, all of the pay intervals are either limestone or dolomite, and all of the oil-bearing pay zones are associated with oil-water contacts. The field is located on a northwest-trending anticline.

2. The Salem field is located in Allegan County and has produced oil from the Traverse limestone (Hake, 1938; Newcombe, 1938; Checkley, 1968). The field was discovered in 1937. The pay zones consist of a 7- to 8-ft-thick bed of cherty dolomite near the top of the Traverse limestone and a 7- to 8-ft-thick bed of fossiliferous limestone approximately 20 to 30 ft below the top of the Traverse limestone. The field is located on a northwest-trending anticline.

3. The Walker field is located in Kent and Ottawa Counties and has produced predominantly oil and some gas from the Traverse limestone (Addison, 1940; Riggs, 1940; Landes, 1944; Wagner and Passero, 1987). The field was discovered in 1938. The main pay zone consists of porous intervals in the Traverse limestone along the crest of a northwest-trending anticline. The anticline is thought to have been created by salt dissolution in the underlying Silurian Salina A-1 and A-2 evaporites.

4. The Calvin impact structure, located in Cass County, is a circular impact structure of Late Ordovician age, delineated by 110 oil and gas test wells (Milstein, 1988, 1996). The structure has a diameter of 9 mi and consists of a central dome with 1,362 ft of structural uplift, an annular depression, and an encircling crater rim. The three oil fields associated with the impact structure are Juno Lake, Calvin 28, and Calvin 20. The Juno Lake and Calvin 20 fields are located on the crater rim, whereas the Calvin 28 field is located on the central dome of the crater. The Juno Lake field, discovered in 1978, produces oil from the Traverse limestone. The Calvin 28 field, discovered in 1980, also produces oil from the Traverse limestone. In the Calvin 28 field, the reservoir interval has low permeability, and it contains well-defined oil-water contacts. This field was initially thought to have a gas cap, but a core taken from the crest of the central dome was oil-saturated to the top of the Traverse limestone, and thus any gas is

likely to be solution-gas that has a bubble point close to the reservoir pressure. The Calvin 20 field, discovered in 1982, consists of several wells that produce oil from the Traverse limestone. The field also has one well that produces oil from an interval that is called the Sylvania Sandstone, although the Sylvania Sandstone has not been mapped in this area, and the producing interval is dolomite and anhydrite rather than sandstone.

Petroleum Geochemistry

Three geochemically distinct oils are produced from carbonate reservoirs in the Middle Devonian Carbonates Assessment Unit. Two oils are produced from reservoirs (Rich and Birch Run fields) in the Detroit River Group and Dundee Limestone interval (Pruitt, 1983); the third oil is produced from reservoirs (Peacock field) in the Traverse limestone (Rullkötter and others, 1986). A gas chromatogram of the saturated-hydrocarbon fraction from oil from the first of these oil families is shown in figure 88. The saturated-hydrocarbon distribution of this oil (from Rich field, Lapeer County, Michigan; location shown on fig. 87) is characterized by an even-carbon predominance in the n-C_{20} to n-C_{26} alkanes. The carbon preference index (CPI, modified from Bray and Evans, 1961) between n-C_{20} and n-C_{26} is 0.92, the pristane/phytane ratio is approximately 1.0, and the pristane/n-C_{17} ratio is 0.21 (all values are from measurements of peak height).

A gas chromatogram of the saturated-hydrocarbon fraction of oil from the second oil family is shown in figure 89**.** The saturated-hydrocarbon distribution of this oil (Dundee Limestone production from the Birch Run field, Saginaw County, Michigan; location shown on fig. 87) is characterized by odd-carbon predominance in the n-C_9 to n-C_{20} alkanes. The carbon preference index (CPI, modified from Bray and Evans, 1961) between n-C_{12} and n-C_{20} is 1.26, the pristane/phytane ratio is about 1.5, and the pristane/n-C_{17} ratio is 0.11 (all values are from measurements of peak height). The hydrocarbon distribution shown in figure 89 is very similar to hydrocarbon distributions of oils produced from the Trenton Formation (see fig. 40) and hydrocarbon distributions shown in Illich and Grizzle (1983, 1985), Powell and others (1984), and Hurley and Budros (1990). The hydrocarbon distributions of these oils are dominated by the geochemical signature of *Gloeocapsamorpha prisca* (an organic-walled microfossil of Cambrian and Ordovician age) (Jacobson and others, 1988).

A gas chromatogram of the saturated-hydrocarbon fraction of oil from the third oil family is shown in figure 90. The saturated-hydrocarbon distribution of this oil (Traverse limestone production from the Peacock field, Lake County, Michigan; location shown on fig. 87) is characterized by slight odd-carbon predominance in the n-C_{20} and n-C_{26} alkanes. The carbon preference index (CPI, modified from Bray and Evans, 1961) between n-C_{20} and n-C_{26} is 1.03, the pristane/phytane ratio is about 1.9, and the pristane/n-C_{17} ratio is about 3.1 (all values are from measurements of peak height). The hydrocarbon distribution shown in figure 90 is very similar to gas chromatographic signatures of Traverse limestone oils illustrated in Illich and Grizzle (1983, 1985) that have been attributed to Antrim Shale petroleum source rocks. The Antrim Shale source rocks will be characterized in the section Ordovician to Devonian Composite Total Petroleum System—Part III.

Petroleum source rocks for the Trenton Formation oils in the Michigan Basin are from intervals within the Trenton Formation and Collingwood Shale. The presence of this oil family in Devonian carbonate reservoirs overlying the Salina evaporite beds in the central part of the Michigan Basin

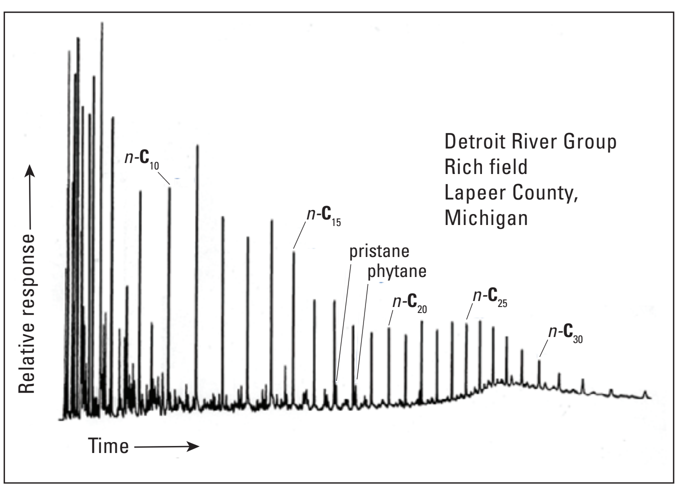


Figure 88. Saturated-hydrocarbon gas chromatogram for oil collected from a well producing from a reservoir in the Middle Devonian Detroit River Group (Rich field) in Lapeer County, Michigan (modified from Pruitt, 1983, her figure1).

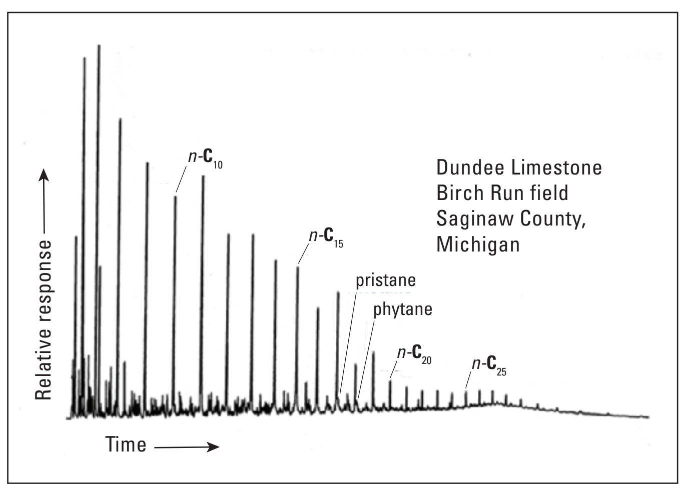


Figure 89. Saturated-hydrocarbon gas chromatogram for oil collected from a well producing from a reservoir in the Middle Devonian Dundee Limestone (Birch Run field) in Saginaw County, Michigan (modified from Pruitt, 1983, her figure 1).

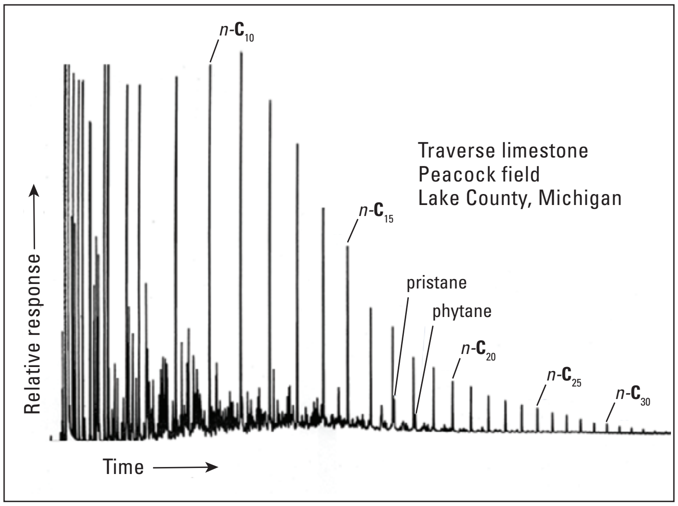


Figure 90. Saturated-hydrocarbon gas chromatogram for oil collected from a well producing from a reservoir in the Middle Devonian Traverse limestone (Peacock field) in Lake County, Michigan (modified from Rullkötter and others, 1986, their figure 4). The reservoir depth is ≈ 2,300 ft.

suggests vertical migration of petroleum, presumably along northwest-trending fractures, which are interpreted as flower structures controlled by deep reactivated basement faults (Hatch and others, 2005). An alternative to this hypothesis is that the organism *Gloeocapsamorpha prisca* survived in the Michigan Basin area approximately 80 million years longer (from Late Ordovician to Middle Devonian) than it survived in other basin areas of North America. This second hypothesis suggests that the organism was present in Middle Devonian petroleum source rocks, and upon reaching thermal maturity, the oil was generated and accumulated in nearby reservoirs. To date, *Gloeocapsamorpha prisca* has not been identified in Middle Devonian strata in the basin.

The chemical compositions (N_2 mole percent, CO_2 mole percent, H_2S mole percent, ethane/isobutane mole percent/mole percent, and gas wetness percent) of 117 natural gas samples collected from wells producing from the Detroit River Group in the central and eastern parts of the Michigan Basin are summarized in table 10, 24 gas samples from the Dundee Limestone are summarized in table 11, and 4 samples from the Traverse limestone are summarized in table 12. The Detroit River Group set of gas samples includes samples labeled as either Detroit River Group or Richfield Member (Lucas Formation). The data summarized in tables 10, 11, and 12 are from Moore and Sigler (1987), Hamak and Sigler (1991), and the data set, Michigan Oil and Gas Well Gas Analyses Data from the Michigan Geological Repository for Research and Education at Western Michigan University (http://wsh060.westhills.wmich.edu/MGRRE/data/). The data in the geographic distribution plots shown in figures 91, 92, 93, and 94 are also from these data sets.

Gas chemical compositions vary between formations and also vary based on location within the central basin. The natural gases produced from the Detroit River Group have a lower N_2 content compared to N_2 content of gases produced from the Dundee Limestone (median = 1.2 mole percent versus 3.9 mole percent, respectively). Gases from the Detroit River Group have a significantly greater CO_2 content compared to CO_2 content of gases produced from the Dundee Limestone (median = 3.6 mole percent versus 0.15 mole percent, respectively) and a significantly higher H_2S content (median = 0.4 mole percent versus <0.01 mole percent, respectively). Natural gases produced from the Detroit River Group also have a lower gas wetness compared to gases produced from the Dundee Limestone (median = 24 percent versus 31 percent, respectively), whereas ethane/isobutane is higher (median = 19 versus 12, respectively).

The geographic distribution of H_2S contents in gas samples from the Detroit River Group and Dundee Limestone from the Michigan Basin is shown in figure 91, and the geographic distribution of CO_2 contents is shown in figure 92. Gas H_2S contents are higher for produced gases on the eastern side of the central basin area, particularly in Lapeer, Tuscola, Genesee, Bay, Ogemaw, and Oscoda Counties, Michigan (fig. 91). Similarly, gas CO_2 contents are also higher in these same counties (fig. 92). A plot of H_2S versus CO_2 contents for 117 natural gas samples produced from the Detroit River Group in the Michigan Basin (fig. 93) shows generally higher CO_2 contents associated with higher H_2S contents; there is a wide range in H_2S contents, from <0.01 to 24 mole-percent H_2S. The relation between (a) high H_2S and CO_2 contents and (b) highly variable H_2S and CO_2 contents suggest that both gases are, at least in part, products of thermo-chemical sulfate-reduction reactions between SO_4^{-2} (from Middle Devonian evaporites) and C_2^+ compounds from petroleum. Similar situations were detailed in Orr (1974, 1982) for Paleozoic oils in the Big Horn Basin in Wyoming and by Worden and Smalley (1996) for reactions in deep carbonate gas reservoirs in Abu Dhabi. Similar gas H_2S/CO_2 relations are shown in figures 64 and 65 in the discussion of H_2S contents of gases from Silurian Niagara Group and Salina Group reservoirs.

Table 10. Statistical summary of the chemical compositions of 117 natural gas samples collected from wells producing from the Middle Devonian Detroit River Group primarily in Clare, Genesee, Isabella, Lapeer, Oscoda, Roscommon, and Tuscola Counties in east-central Michigan.

[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	117	117	117	117	117
Median	1.2	3.6	0.4	19	24
Average, Standard deviation	2.0 ± 2.9	3.0 ± 2.0	3.3 ± 5.0	21 ± 9.6	24 ± 9.1
Range	0.1–22	0.06–7.9	<0.01–24	6.9–57	6.7–53

Table 11. Statistical summary of the chemical compositions of 24 natural gas samples collected from wells producing from the Middle Devonian Dundee Limestone primarily from Clare, Isabella, Lapeer, Mecosta, and Ogemaw Counties in east-central Michigan.

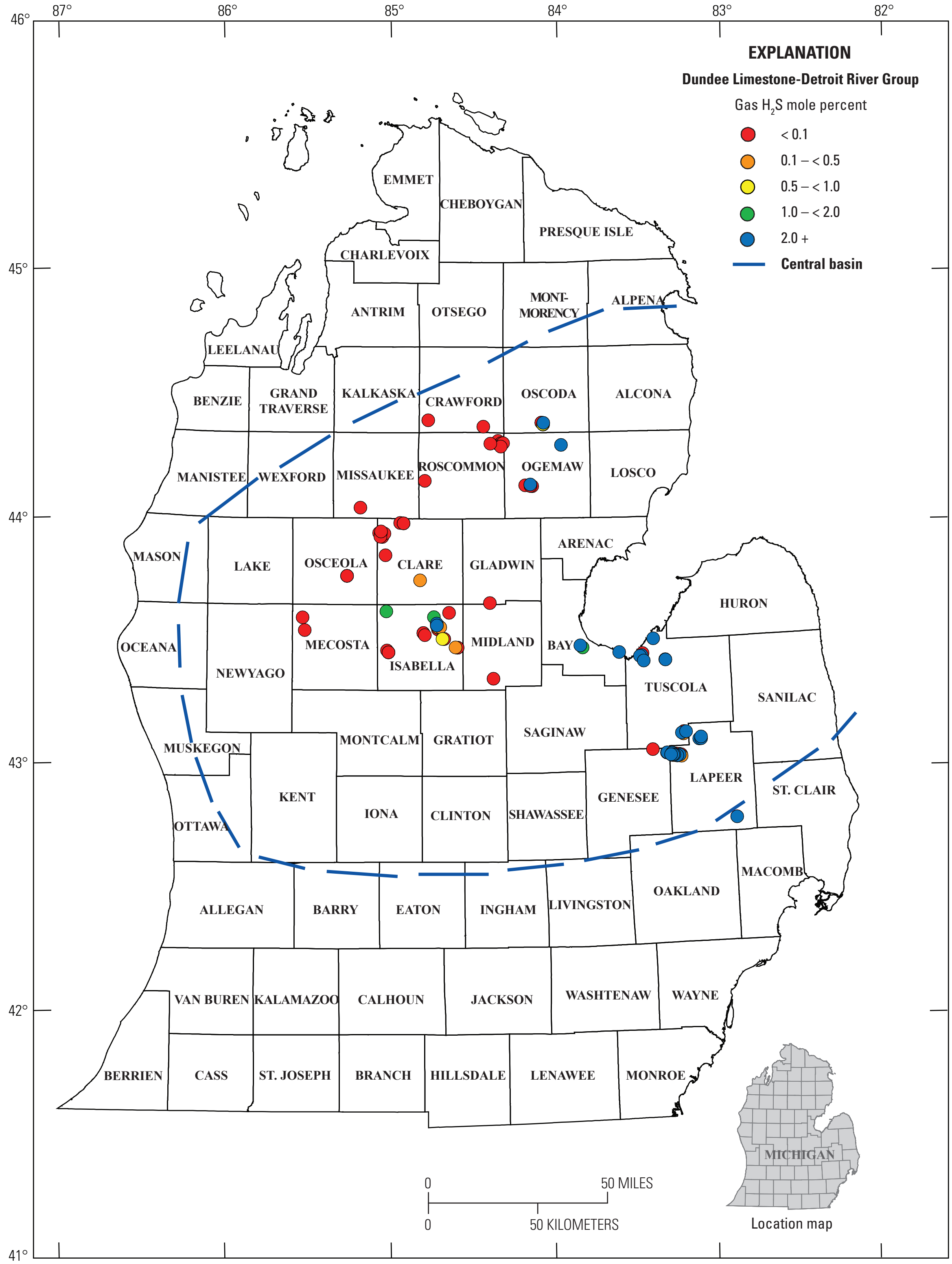
[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	24	24	24	19	24
Median	3.9	0.15	<0.01	12	31
Average, Standard deviation	3.8 ± 2.0	0.5 ± 0.9	0.1 ± 0.3	15 ± 7.3	31 ± 12
Range	0.4–8.4	<0.01–3.2	<0.01–1.3	6.3–28	15–49

Table 12. Statistical summary of the chemical compositions of four natural gas samples collected from wells producing from the Middle Devonian Traverse limestone in Kalkaska, Missaukee, and Roscommon Counties in north-central Michigan.

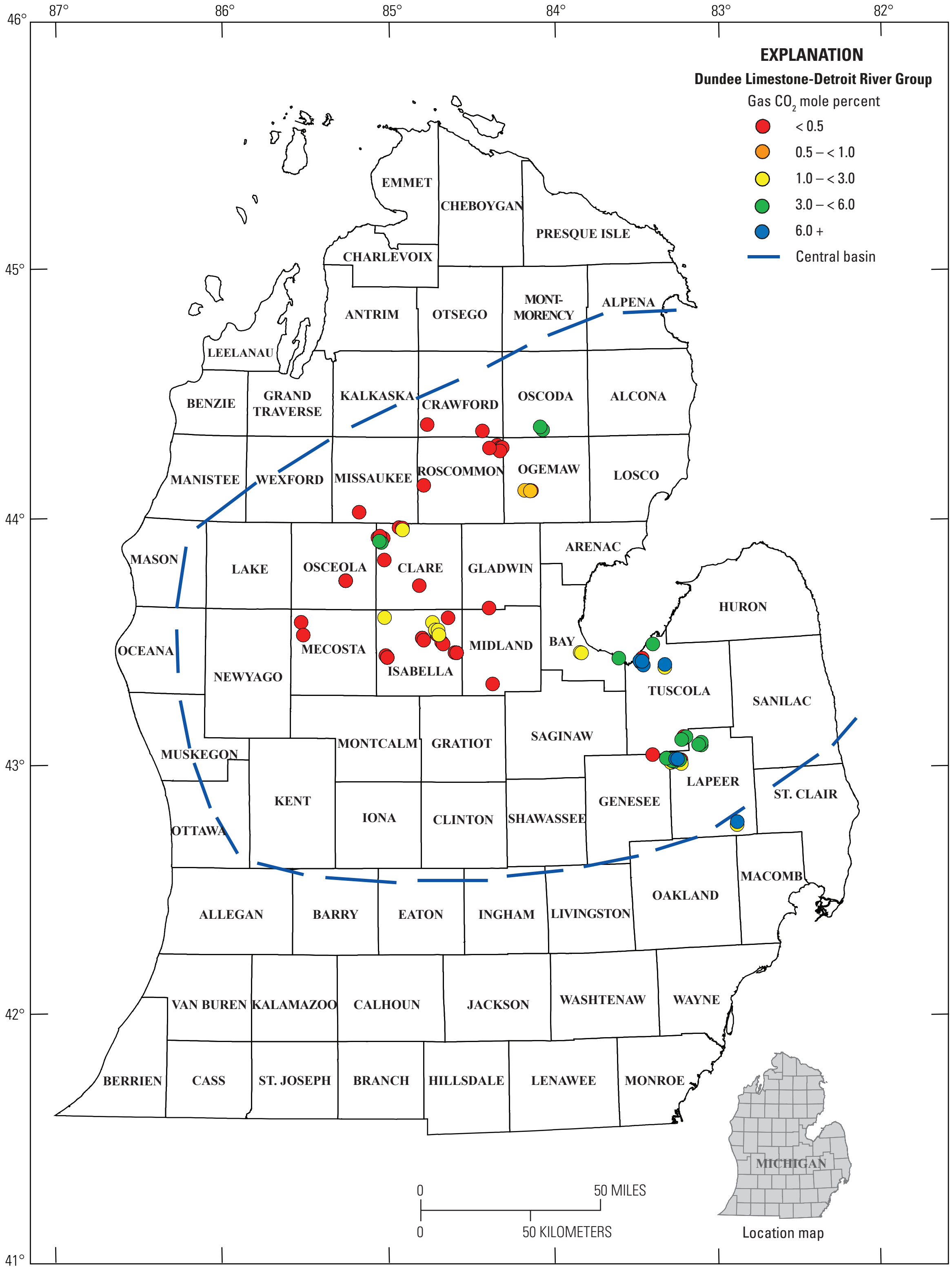
[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	4	4	4	4	4
Median	1.8	0.6	<0.01	22	19
Average, Standard deviation	2.4 ± 2.5	1.3 ± 1.8	0.2 ± 0.3	23 ± 11	22 ± 8.6
Range	0.3–5.5	<0.01–4.0	<0.01–0.6	9.4–38	16–35



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 91. Map showing the geographic distribution of hydrogen sulfide (H_2S) contents (mole percent) for 141 natural gas samples collected from wells producing from the Middle Devonian Detroit River Group and Middle Devonian Dundee Limestone in the central part of the Michigan Basin.



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 92. Map showing the geographic distribution of carbon dioxide (CO_2) contents (mole percent) for 141 natural gas samples collected from wells producing from the Middle Devonian Detroit River Group and Middle Devonian Dundee Limestone in the central part of the Michigan Basin.

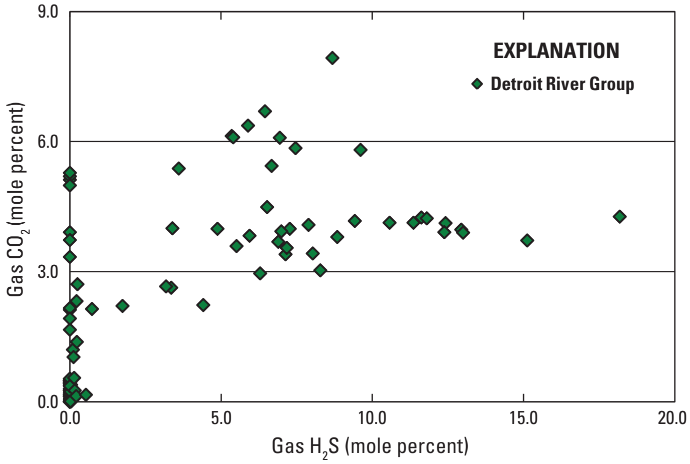


Figure 93. Plot of hydrogen sulfide (H_2S) content (mole percent) versus carbon dioxide (CO_2) content (mole percent) for 117 natural gas samples collected from wells producing from the Middle Devonian Detroit River Group in the central part of the Michigan Basin.

The geographic distribution of N_2 contents in the Detroit River Group and Dundee Limestone natural gases from the central part of the Michigan Basin is shown in figure 94. No apparent pattern in N_2 contents exists with respect to position in the basin or depths to the top of the Detroit River Group. Similarly, no apparent pattern exists for either ethane/isobutane or gas wetness percent in the Detroit River Group or in the Dundee Limestone.

Undiscovered Petroleum Resources

In the 2004 assessment of the U.S. portion of the Michigan Basin, the USGS assessed the Middle Devonian Carbonates AU as a conventional petroleum accumulation. The assessment unit was considered to be primarily oil-prone, and the undiscovered fields were estimated to be only oil fields. For the oil fields, the estimated volumes of undiscovered, technically recoverable oil resources are 10.8 MMBO at the 95-percent certainty level, 43.4 MMBO at the 50-percent certainty level, 108 MMBO at the 5-percent certainty level, and a mean of 50.5 MMBO. For the associated natural gas, the estimated volumes are 5.1 BCGF at the 95-percent certainty level, 22.0 BCFG at the 50-percent certainty level, 56.9 BCFG at the 5-percent certainty level, and a mean of 25.3 BCFG. For the associated natural gas liquids, the estimated volumes are 0.4 MMBNGL at the 95-percent certainty level, 1.7 MMBNGL at the 50-percent certainty level, 4.7 MMBNGL at the 5-percent certainty level, and a mean of 2.0 MMBNGL (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).

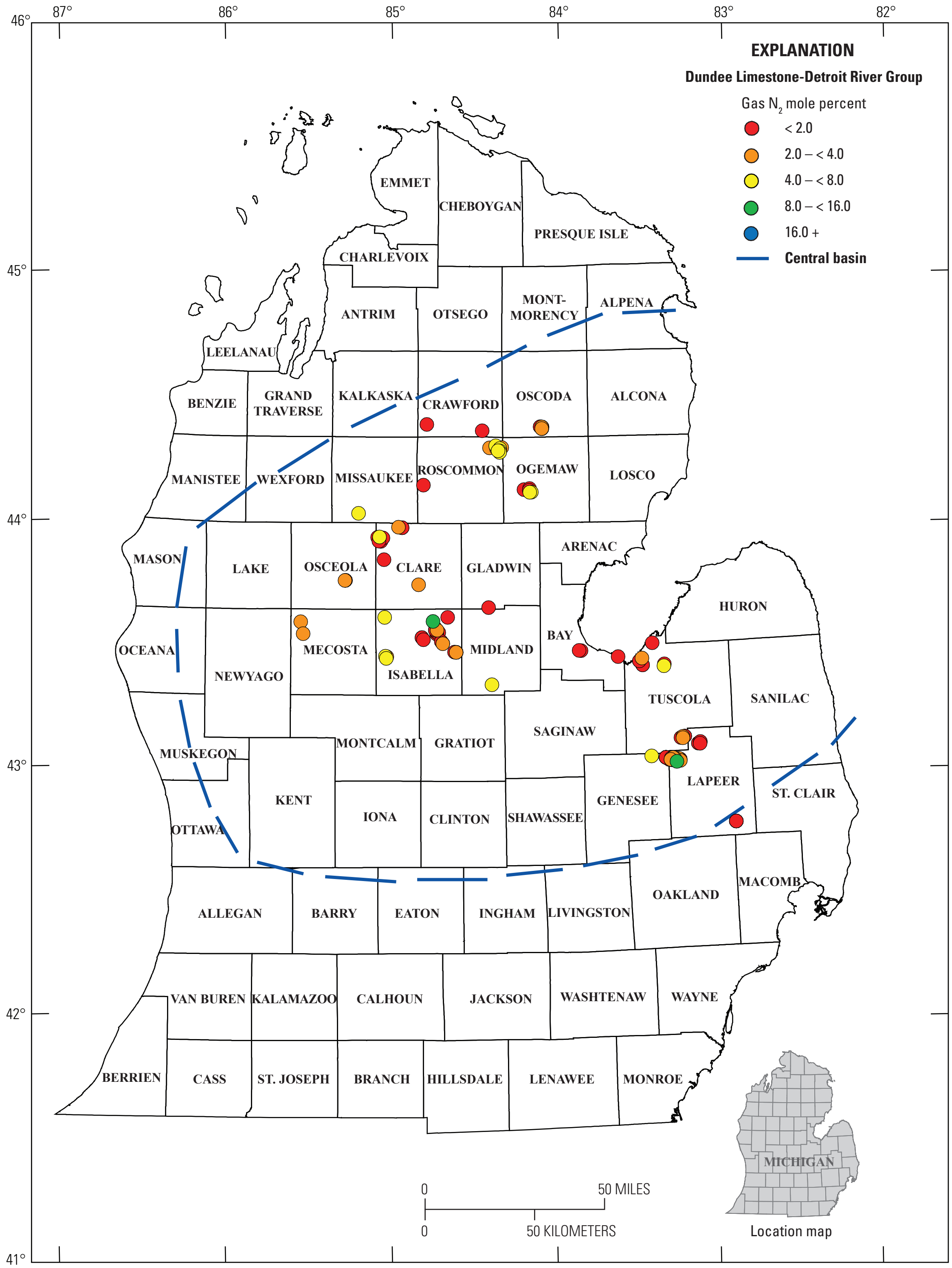
For the assessment calculations, a minimum grown field size of 0.5 MMBO equivalent was used for oil fields, and a minimum grown field size of 3 BCFG was used for gas fields. As of 2004, the Middle Devonian Carbonates AU contained 84 known oil fields and no known gas fields with grown field sizes exceeding the minimum sizes. Also as of 2004, the assessment unit was estimated to have produced a cumulative of 575 MMBO and 141 BCFG in Michigan (figs. 9 and 10). The numbers of undiscovered accumulations greater than the minimum grown field size were estimated as follows: minimum = 1 oil accumulation, mode = 8 oil accumulations, and maximum = 35 oil accumulations. The sizes of undiscovered accumulations greater than the minimum grown field size were estimated as follows: minimum = 0.5 MMBO, median = 2 MMBO, and maximum = 60 MMBO.

Ordovician to Devonian Composite Total Petroleum System—Part III

The Ordovician to Devonian Composite TPS is based on the presence of three separate petroleum source-rock intervals and evidence for significant vertical petroleum migration and mixing of petroleum through much of the Ordovician through Devonian stratigraphic section. The three petroleum source-rock intervals are (1) Middle Ordovician Trenton Formation and Collingwood Shale, (2) Middle Devonian Detroit River Group (Amherstburg and Lucas Formations), and (3) Upper Devonian Antrim Shale (fig. 5). Part III of the Ordovician to Devonian Composite TPS focuses on the stratigraphically higher (Upper Devonian through Lower Mississippian) petroleum source-rock intervals and petroleum reservoirs identified within this total petroleum system. Part III includes the discussion and assessment of two assessment units: (1) the Devonian Antrim Continuous Oil AU and (2) the Devonian to Mississippian Berea/Michigan Sandstones AU.

Thermally mature, organic-matter-rich intervals in the Upper Devonian Antrim Shale and the partly stratigraphically equivalent Upper Devonian Ellsworth Shale contribute petroleum to the Devonian Antrim Continuous Oil AU and to the Devonian to Mississippian Berea/Michigan Sandstones AU. In addition, these shales are sources for biogenic gases that are produced from the Antrim Shale and Ellsworth Shale in the northern part of the Michigan Basin. Assessment of this biogenic gas is described in a subsequent section "The Devonian Antrim Shale Total Petroleum System."

The Antrim Shale and the Ellsworth Shale primarily consist of black, gray, and green shale, although the Ellsworth Shale contains some beds of fine-grained sandstone in the western part of the basin. Throughout most of its extent, the thickness of the Antrim Shale (fig. 95) ranges from 200 to 600 ft, whereas the thickness of the Ellsworth Shale (fig. 96) ranges from 200 to 800 ft. Elevations at the base of the Antrim Shale (fig. 97) range from about 500 ft above sea level in both the southern and northern parts of the basin to more than 2,000 ft below sea level in the central part (fig. 97). As described by Matthews (1993), the Antrim Shale rests on shale of the Squaw Bay Limestone and limestones of the Traverse Group (fig. 98). In southeast Michigan, an erosional unconformity may be present between the Antrim



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 94. Map showing the geographic distribution of nitrogen (N_2) contents (mole percent) for 141 natural gas samples collected from wells producing from the Middle Devonian Detroit River Group and Middle Devonian Dundee Limestone in the central part of the Michigan Basin.

The base map for this figure is from Nicholson and others (2004).

Figure 95. Map of isopachs of the Upper Devonian Antrim Shale in the central part of the Michigan Basin (after Gutschick and Sandberg, 1991b). Ot, Otsego County.

The base map for this figure is from Nicholson and others (2004).

Figure 96. Map of isopachs of the Upper Devonian Ellsworth Shale in the central part of the Michigan Basin (after Gutschick and Sandberg, 1991b).

The base map for this figure is from Nicholson and others (2004).

Figure 97. Structure map on the base of the Upper Devonian Antrim Shale in the central part of the Michigan Basin (after Matthews, 1993).

Shale and the underlying Traverse Group. Matthews (1993) informally divided the Antrim Shale into lower and upper parts, which are separated by a bed containing algal spores of *Foerstia* (fig. 98). To the west, the upper part of the Antrim Shale interfingers with the Ellsworth Shale, which rests on the lower part of the Antrim Shale (fig. 98). The lower part of the Antrim Shale is divided into (from base to top): (1) the Norwood Member, (2) the Paxton Member, and (3) the Lachine Member (fig. 99). Both the Antrim Shale and the Ellsworth Shale are capped by an unconformity, above which lie the Upper Devonian Bedford Shale and Upper Devonian Berea Sandstone (fig. 99). In the western part of the basin, however, the Bedford Shale and Berea Sandstone may interfinger with the Ellsworth Shale.

Upper Devonian Petroleum Source Rocks

The Antrim Shale and the partly laterally equivalent Ellsworth Shale are petroleum source rocks. Within these units, the primary organic-matter-rich shale intervals are in the Norwood and Lachine Members of the Antrim Shale (fig. 99). Both of these members are in the lower part of the Antrim Shale. There is also an unnamed organic-matter-rich shale at the top of the Antrim Shale (fig. 99). Both the Norwood and Lachine Members of the Antrim Shale consist of black shale with abundant carbonate concretions with cements consisting of carbonate, sulfate, and sulfide. Organic-carbon contents in the Norwood and Lachine Members range from 0.5 to 24 weight percent; silica contents range from 20 to 41 weight percent (Martini and others, 1998).

Several published studies document organic-carbon contents of the Antrim Shale and equivalent strata, and provided Rock-Eval pyrolysis analyses of Antrim Shale samples. Powell and others (1984) lists organic-carbon contents for five samples and Snowdon (1984) lists organic-carbon contents and Rock-Eval pyrolysis analyses for an additional five samples, with both sets of samples from the Kettle Point Formation (stratigraphically equivalent to the Antrim Shale) in Ontario, Canada. Dellapenna (1991) lists organic-carbon contents (fig. 100) and Rock-Eval pyrolysis analyses for 46 samples

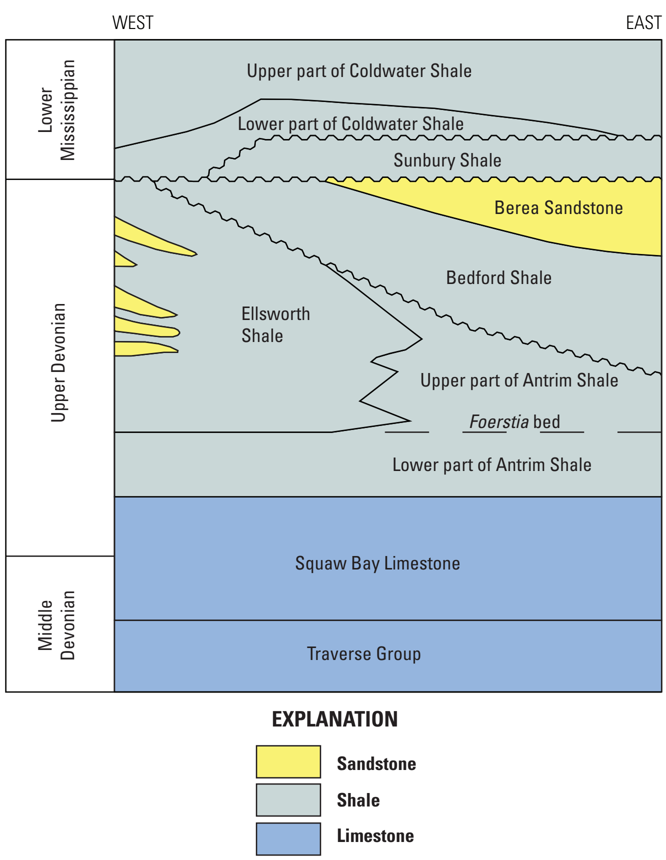


Figure 98. Schematic Middle Devonian to Lower Mississippian stratigraphy in Michigan (modified from Matthews, 1993).

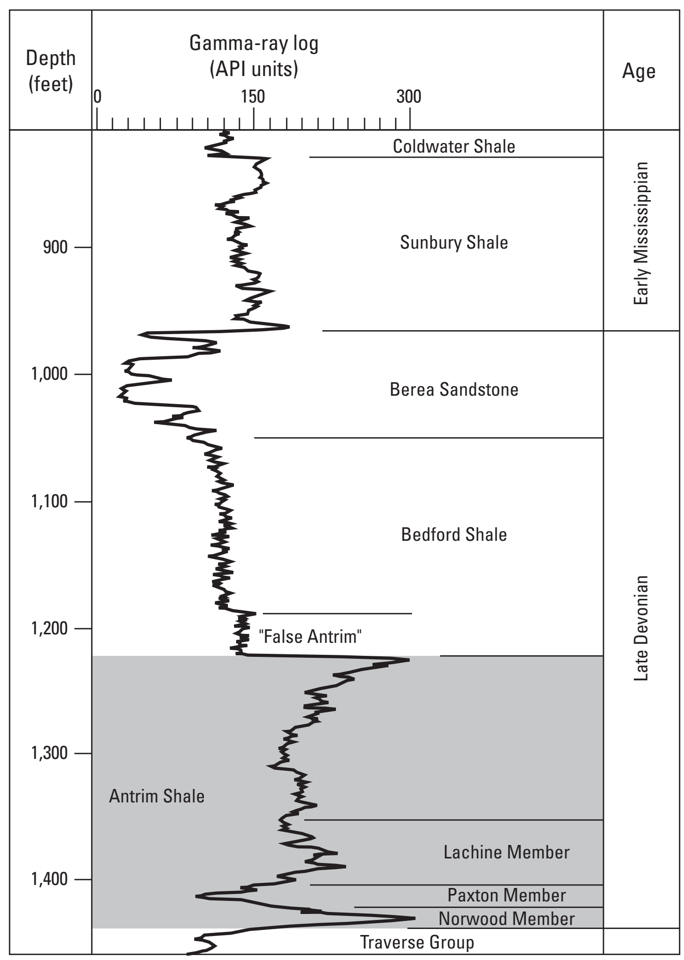


Figure 99. Well log from the Dow Chemical Company Rhoburn No. 1 well, Sanilac County, Michigan, showing the stratigraphy of the Upper Devonian Antrim Shale (modified from Matthews, 1993; Gutschick and Sandberg, 1991a). API, American Petroleum Institute.

from three cores from Otsego County, Michigan, and Matthews (1993) provides graphic profiles of organic-carbon contents for 26 samples from a core from Sanilac County, Michigan. Figure 101 is a histogram showing the distribution of total organic-carbon (weight percent) contents for 46 samples of the Upper Devonian Antrim Shale in Otsego County, Michigan (Dellapenna, 1991), and for 26 samples of the Antrim Shale in Sanilac County, Michigan (data from Matthews, 1993).

Hydrogen indices (HI, in milligrams per gram (mg/g); Rock-Eval pyrolysis analysis) of organic matter from the Antrim Shale showed a wide range of compositions. For example, Dellapenna (1991) reported that HI for 17 samples of gray shale range from 52 to 586 mg/g, whereas HI for 29 samples of black shale range from 480 to 840 mg/g (fig. 101). All of these samples were from the Latuszek B1-32 well in Otsego County, Michigan.

Jones (1987) defined a classification of organic facies (labeled A, AB, B, BC, C, CD, and D in fig. 101) for organic matter in rocks based on microscopic and chemical characteristics (HI and hydrogen/carbon ratios) of organic matter that is marginally mature with respect to petroleum generation. Organic facies A has the greatest potential to generate oil, and organic facies AB also has great potential to generate oil, although organic facies B has generated most of the oil in the world. Organic facies BC usually generates both oil and gas, and organic facies C usually generates condensate and gas. Organic facies CD has a moderate capacity to generate dry gas, whereas organic facies D is essentially nongenerative (Jones, 1987). The organic matter of black shale in the Antrim Shale consists primarily of organic facies AB and B, whereas organic matter in beds of gray shale in the Antrim Shale consists primarily of organic facies BC (fig. 101). Thus, where

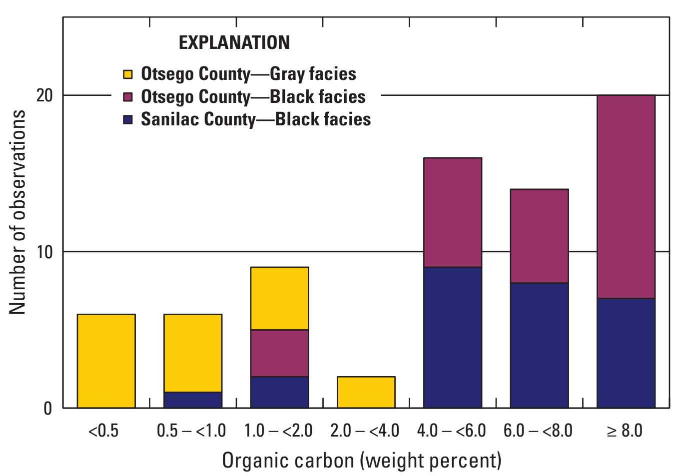


Figure 100. Histogram showing the distribution of organic-carbon contents (weight percent) in the gray and black facies for 46 core samples of the Upper Devonian Antrim Shale in Otsego County, Michigan (Dellapenna, 1991), and in the black facies for 26 core samples of the Antrim Shale in Sanilac County, Michigan (Matthews, 1993).

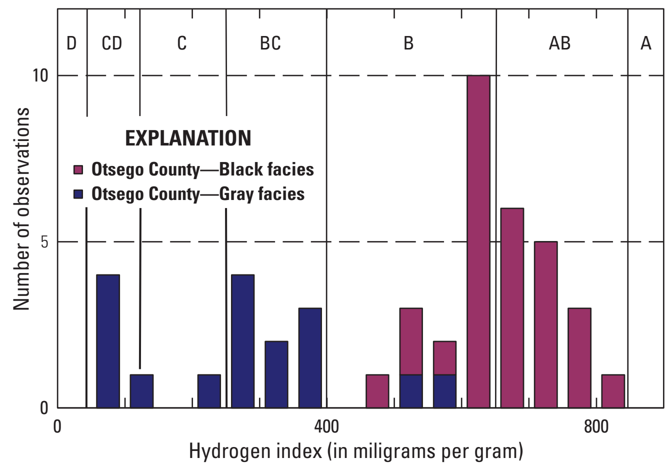


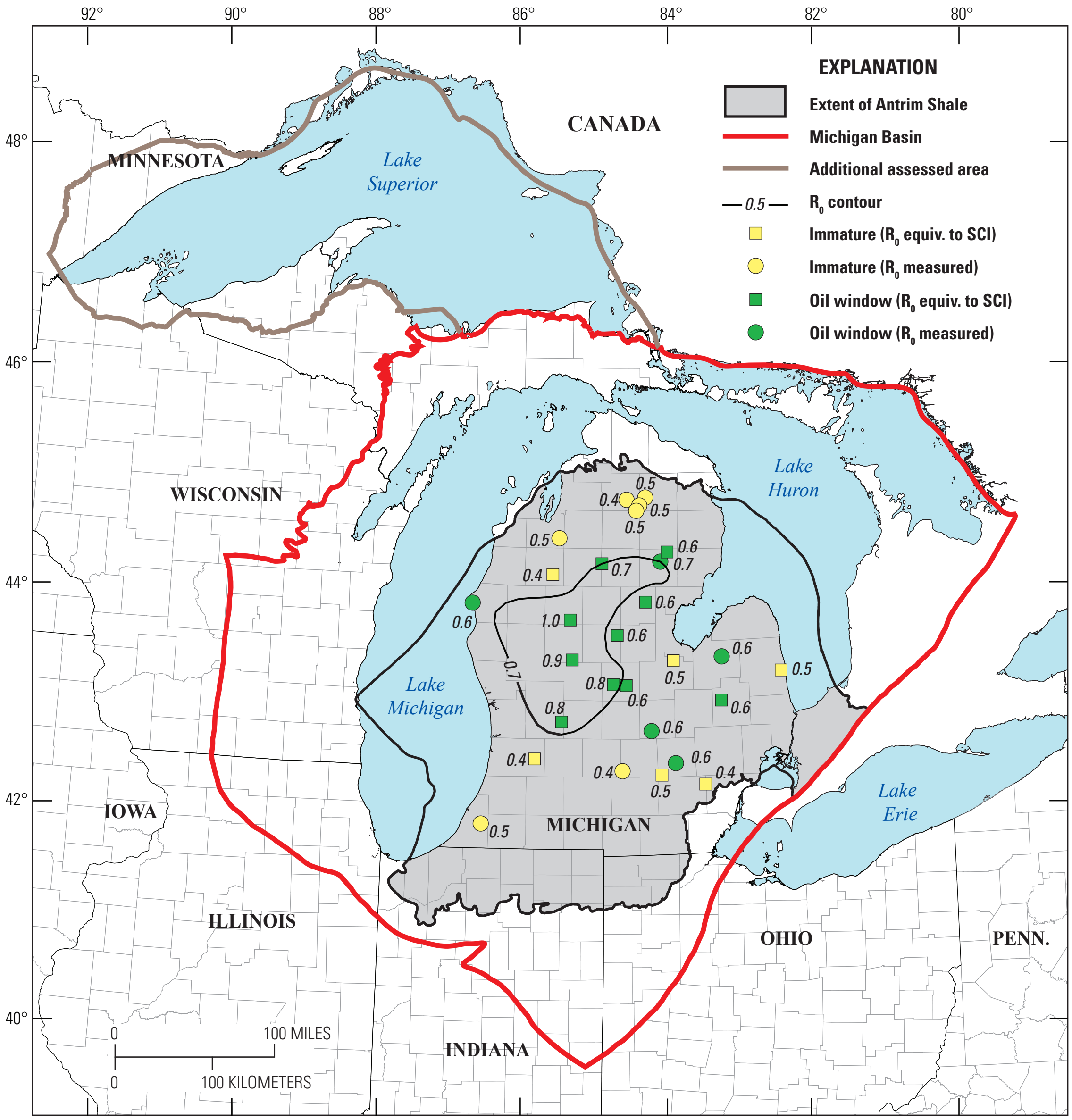
Figure 101. Histogram showing the distribution of hydrogen indices (in milligrams per gram) for 46 core samples from black and gray facies in the Upper Devonian Antrim Shale in Otsego County, Michigan (data from Dellapenna, 1991) (Rock-Eval T_{max} ≤440 °C for all samples). Organic facies boundaries (D, CD, C, and so forth) are from Jones (1987). Location of Otsego County is shown in figure 95.

thermally mature, the beds of black shale should generate primarily oil, whereas the beds of gray shale should generate both oil and gas.

Vitrinite reflectance measures (R_o percent), or vitrinite equivalent measures (sporopollen coloration index, SCI) that range from 0.4 to 0.6 percent, indicate thermally immature to marginally mature organic matter, whereas measures that range from 0.6 to 1.3 percent R_o indicate organic matter is thermally mature and has entered the oil window. In figure 102, R_o percent and SCI measures show that on the basin margin, organic matter in the Antrim and Ellsworth Shales is thermally immature to marginally mature; in the central part of the basin, the organic matter is thermally mature (within the oil window). The R_o percent and SCI data in figure 102 are from Rullkötter and others (1992). The level of thermal maturity for the Antrim Shale indicated in figure 102 is supported by the Rock-Eval T_{max} data that range from 429 to 443 °C for 46 samples from Otsego County (Dellapenna, 1991). This range in T_{max} measures would indicate thermally immature to marginally mature organic matter (Espitalié and others, 1977).

Devonian Antrim Shale Continuous Oil Assessment Unit

The Devonian Antrim Shale Continuous Oil AU includes both the Antrim Shale and the partly stratigraphically equivalent Ellsworth Shale. The Antrim Shale ranges in thickness from about 100 to 600 ft; the Ellsworth Shale ranges from about 200 to 800 ft thick (figs. 95 and 96). Elevations at the base of the Antrim Shale (fig. 97) range from about 500 ft



The base map for this figure is from Nicholson and others (2004).

Figure 102. Map showing the thermal maturity of organic matter in the Upper Devonian Antrim Shale in the central part of the Michigan Basin (modified from Moyer, 1982; Cercone, 1984; Everham and Huntoon, 1999; Hayba, 2005). Thermal maturity is based on measured vitrinite reflectance (percent R_o) and the percent R_o equivalent (equiv.) to measured sporopollen coloration index (SCI) values. With respect to petroleum generation, <0.6 percent R_o = immature and 0.6 to 1.3 percent R_o = oil window.

above sea level in the southern and northern parts of the basin to more than 2,000 ft below sea level in the central part (fig. 98). The Antrim Shale consists primarily of black and gray shale; the Ellsworth Shale also consists primarily of shale, although, in the western part of the basin, the Ellsworth Shale contains some beds of fine-grained sandstone and dolomite. Isopach maps of the Norwood and Lachine Members of the Antrim Shale are shown in figures 103 and 104. Most studies of this stratigraphic interval have focused on the Antrim Shale, which contains the algal spores, *Tasmanites* and *Foerstia*, as well as a few trace fossils (Harrell and others, 1991).

Assessment Unit Model

The Devonian Antrim Shale Continuous Oil AU is considered to be an unconventional petroleum accumulation. Studies by Martini and others (1996, 1998) have shown that some gas from the Antrim Shale in the middle of the Michigan Basin is of thermogenic origin. The petroleum source rocks are within the Antrim and Ellsworth Shales (predominantly the Norwood and Lachine Members of the Antrim Shale). Petroleum generation in the Antrim and Ellsworth Shales may have started during the Pennsylvanian or Permian, when the shale beds entered the oil window in the deepest part of the basin (Hayba, 2005). Oil generated from the shales in this assessment unit may have migrated only locally within the shales; any generated associated gas might have migrated greater distances, possibly to reservoirs higher in the stratigraphic section. Petroleum has not been collected from either the Antrim or the Ellsworth. Hence, there are no analyses to help determine if any oil has migrated into the Antrim or Ellsworth from lower in the stratigraphic section. Within the assessment unit, the Antrim Shale itself forms both reservoir traps and seals.

Reservoir Characteristics

As of the 2004 assessment, petroleum had not been produced commercially from the Devonian Antrim Shale Continuous Oil AU, although shales within the assessment interval are potential reservoirs for oil. If oil production were to be established, then it would probably be from the Antrim Shale in the deepest part of the basin where the shales have greater thermal maturity.

Undiscovered Petroleum Resources

For the 2004 assessment of undiscovered, technically recoverable oil and gas resources of the U.S. portion of the Michigan Basin, the USGS identified the Devonian Antrim Shale Continuous Oil AU but did not quantitatively assess it (Swezey and others, 2005, their table 1). At the time of the assessment, no petroleum production had been established from the assessment unit, and not enough information was available to conduct a quantitative assessment.

Devonian to Mississippian Berea/Michigan Sandstones Assessment Unit

Formations in the Devonian to Mississippian Berea/Michigan Sandstones AU primarily consist of sandstone and shale. Stratigraphic intervals in the assessment unit include (from base to top) (1) Upper Devonian Berea Sandstone, (2) Lower Mississippian Sunbury Shale, (3) Lower Mississippian Coldwater Shale, (4) Lower Mississippian Marshall Sandstone, and (5) Upper Mississippian Michigan Formation (figs. 98, 99, and 105). Based on the cross section shown in figure 105**,** thickness of the assessment unit is about 1,600 ft. Petroleum from the assessment unit is produced primarily from the Berea Sandstone and the Michigan Formation.

The Berea Sandstone is gray, yellow, or brown, micaceous, fine-grained sandstone that contains some gray shale in places (Tarbell, 1941). The formation ranges in thickness from 20 to 100 ft throughout much of its extent (fig. 106), and elevations at the base of the Berea Sandstone range from about 400 ft above sea level to 2,000 ft below sea level (fig. 107). In eastern Michigan, the Berea Sandstone overlies the Bedford Shale (gray shale); the contact is gradational. To the west, however, the Berea Sandstone and Bedford Shale interfinger with the Ellsworth Shale (fig. 105). The Berea Sandstone is unconformably overlain by the Sunbury Shale (fig. 98).

Cohee and Landes (1958) describe three units within the Berea Sandstone in the Michigan Basin: (1) a lower unit of fine-grained dolomitic sandstone that is silty and shaly in places, (2) a middle unit of friable and porous sandstone, and (3) an upper unit of fine-grained dolomitic sandstone that is silty and shaly in places. Hale (1941) describes a unit of sandy dolomite in western Michigan that occupies the same stratigraphic position as the Berea Sandstone in eastern Michigan but acknowledges that it is incorrect to apply the name "Berea" to this western unit.

The Sunbury Shale is a black to dark-gray pyritiferous shale (Tarbell, 1941; Matthews, 1993). Across much of the basin, the formation is generally less than 60 ft thick, although thicknesses greater than 140 ft are present on the eastern side of the basin (fig. 108). Elevations at the base of the Sunbury Shale (fig. 105) range from about 400 ft above sea level to 1,900 ft below sea level. The Sunbury Shale is disconformably overlain by the Coldwater Shale (Matthews, 1993) (see fig. 98).

The Coldwater Shale is a green to blue shale that coarsens upward and has a gradational contact with the overlying Marshall Sandstone (Tarbell, 1941; Briggs, 1968; Matthews, 1993). According to Briggs (1968), the formation attains a maximum thickness of about 1,300 ft. In places, the Coldwater Shale contains lenses of limestone, dolomite, red shale, and green shale. The Coldwater Shale is generally more calcareous in western Michigan and sandier in the eastern Michigan (Hard, 1938). The base of the Coldwater Shale is characterized by red calcareous shale (called "Red Rock") with abundant marine fossils. In Kent and Ottawa Counties, the "Red Rock" is underlain by a thin oolitic limestone. In eastern Michigan,

The base map for this figure is from Nicholson and others (2004).

Figure 103. Map of isopachs of the Upper Devonian Norwood Member of the Antrim Shale in the central part of the Michigan Basin (after Gutschick and Sandberg, 1991b).

The base map for this figure is from Nicholson and others (2004).

Figure 104. Map of isopachs of the Upper Devonian Lachine Member of the Antrim Shale in the central part of the Michigan Basin (after Gutschick and Sandberg, 1991b).

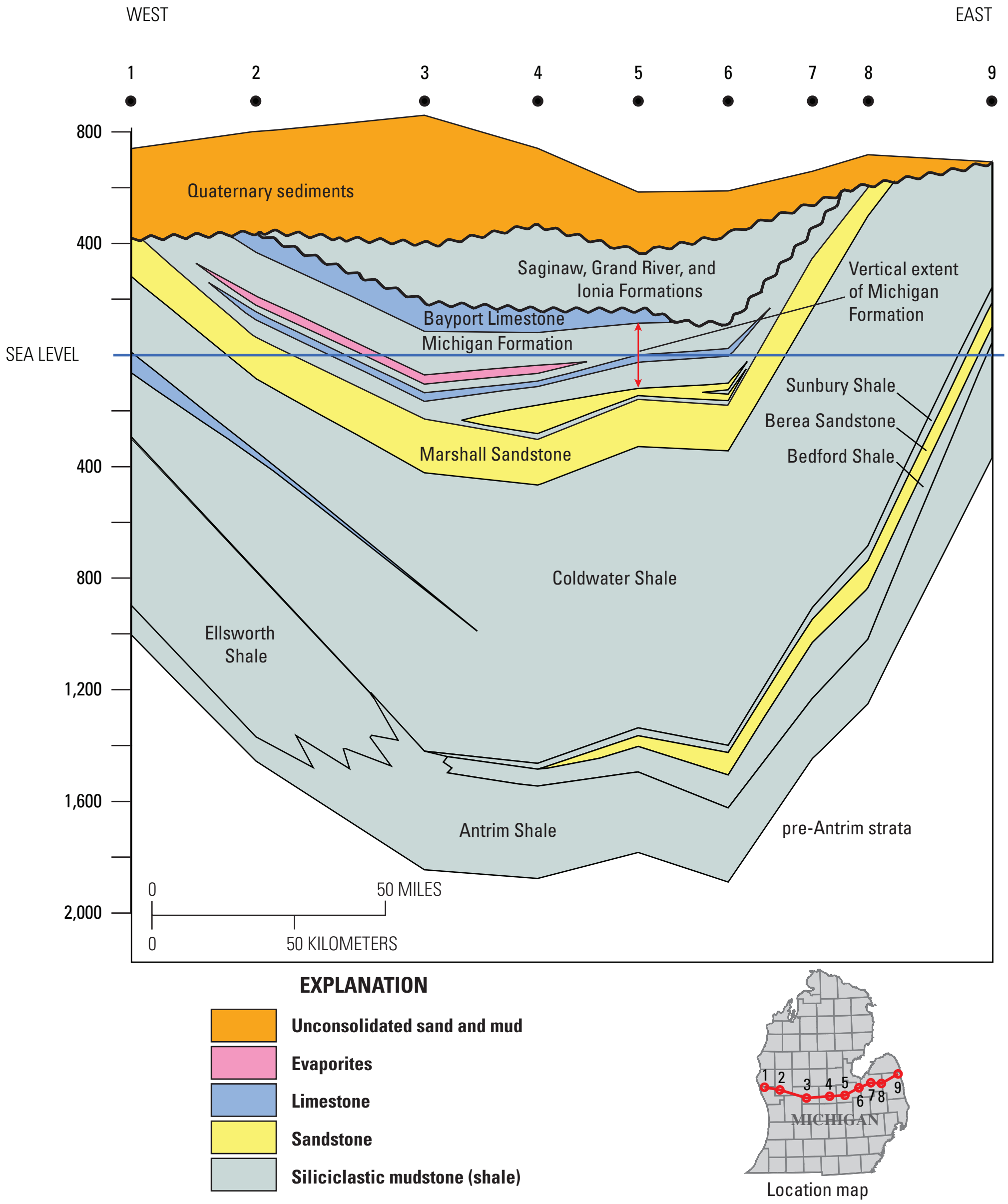


Figure 105. West to east cross section through the Michigan Basin showing the Upper Devonian and higher strata (modified from Ells, 1979b; Harrell and others, 1991). The vertical scale is feet relative to sea level.

The base map for this figure is from Nicholson and others (2004).

Figure 106. Map of isopachs of the Upper Devonian Berea Sandstone in the central part of the Michigan Basin (after Gutschick and Sandberg, 1991b).

The base map for this figure is from Nicholson and others (2004).

Figure 107. Structure map on the base of the Upper Devonian Berea Sandstone and correlative strata in the central part of the Michigan Basin (after Wylie and Wood, 2005). In western Michigan, the Berea Sandstone stratigraphic interval may be occupied by a sandy dolomite (Hale, 1941).

The base map for this figure is from Nicholson and others (2004).

Figure 108. Map of isopachs of the Lower Mississippian Sunbury Shale in the central part of the Michigan Basin (after Matthews, 1993).

the Coldwater Shale contains several sandstone lenses, similar in appearance to the underlying Berea Sandstone (Tarbell, 1941). In southwestern Michigan, where the Sunbury Shale is absent, the contact between Coldwater Shale and the underlying Ellsworth Shale is an unconformity. The Coldwater Shale is gradationally overlain by the Marshall Sandstone (Hard, 1938).

The Marshall Sandstone consists of gray, pink, and red sandstone and siltstone (Tarbell, 1941; Dorr and Eschman, 1970; Briggs, 1968; Matthews, 1993). According to Briggs (1968), the formation attains a maximum thickness of 350 ft. The Marshall Sandstone is divided into the “lower” Marshall and the “upper” Marshall (or Napoleon Sandstone). The lower Marshall is red and contains marine fossils, whereas the upper Marshall has a lighter color and lacks fossils. In places, a shale bed separates the lower and upper Marshall (Hard, 1938). The Marshall Sandstone is a regional aquifer that locally contains gas (Zacharias and others, 1992). The Marshall Sandstone is capped by an erosional disconformity, which is overlain by the Michigan Formation (Prouty, 1988).

The Michigan Formation is a gray, green, blue, and black gypsiferous and micaceous shale and limestone with irregular and lenticular sandstone bodies (informally named the “stray sandstone”) at the base (Hard, 1938; Briggs, 1968; Conybeare, 1976; Wilson, 1983). In central Michigan, the formation ranges up to about 300 ft thick (fig. 105), and elevations at the top of the stray sandstone (fig. 109) range from about 400 ft above sea level to 200 ft below sea level. Thick beds of gypsum and anhydrite occur in the lower part of the formation, and the formation becomes sandier to the southeast. Many fluvial channels are cut into and through the Michigan Formation. The stray sandstone rests on an unconformity above the Marshall Formation. The stray sandstone bodies are overlain by dolomitic and gypsiferous siliciclastic and carbonate mudstone. About 98 to 164 ft above the stray sandstone, there is a calcareous unit that is informally named the “brown lime.” The perimeter of the Michigan Formation is interpreted as an erosional edge (Conybeare, 1976); the Michigan Formation is overlain by the Upper Mississippian Bayport Limestone.

Assessment Unit Model

The Devonian to Mississippian Berea/Michigan Sandstones AU includes the Berea Sandstone, Sunbury Shale, Coldwater Shale, Marshall Sandstone, and Michigan Formation. Both oil and gas have been produced from the upper part of the Berea Sandstone (Cohee and Landes, 1958), whereas mostly gas has been produced from the stray sandstone of the Michigan Formation.

The Devonian to Mississippian Berea/Michigan Sandstones AU contains conventional petroleum accumulations. The petroleum source rocks are within the Antrim Shale. The available petroleum chemical analyses summarized in subsequent sections of this report do not support any significant contribution of petroleum from Ordovician or Devonian source rocks lower in the stratigraphic section. Petroleum generation in the Antrim Shale and the Ellsworth Shale may have begun to occur during the Pennsylvanian or Permian when the shale beds entered the oil window in the deepest part of the basin (Hayba, 2005). Reservoir traps in this assessment unit are both structural and stratigraphic, and most reservoirs are located along northwest-trending anticlines. Siliciclastic mudstones (shale) within and above the Berea Sandstone and Michigan Formation provide reservoir seals.

Reservoir Characteristics

Most reservoirs within the Devonian to Mississippian Berea/Michigan Sandstones AU have produced oil and gas from the Berea Sandstone or from the Michigan Formation. Most of the fields that produce from the Berea Sandstone and (or) from the Michigan Formation are located on northwest-trending anticlines in central Michigan (fig. 110). In addition, several fields in the Michigan Basin produce both gas from the Michigan Formation and oil from underlying Middle Devonian carbonate strata.

Berea Sandstone

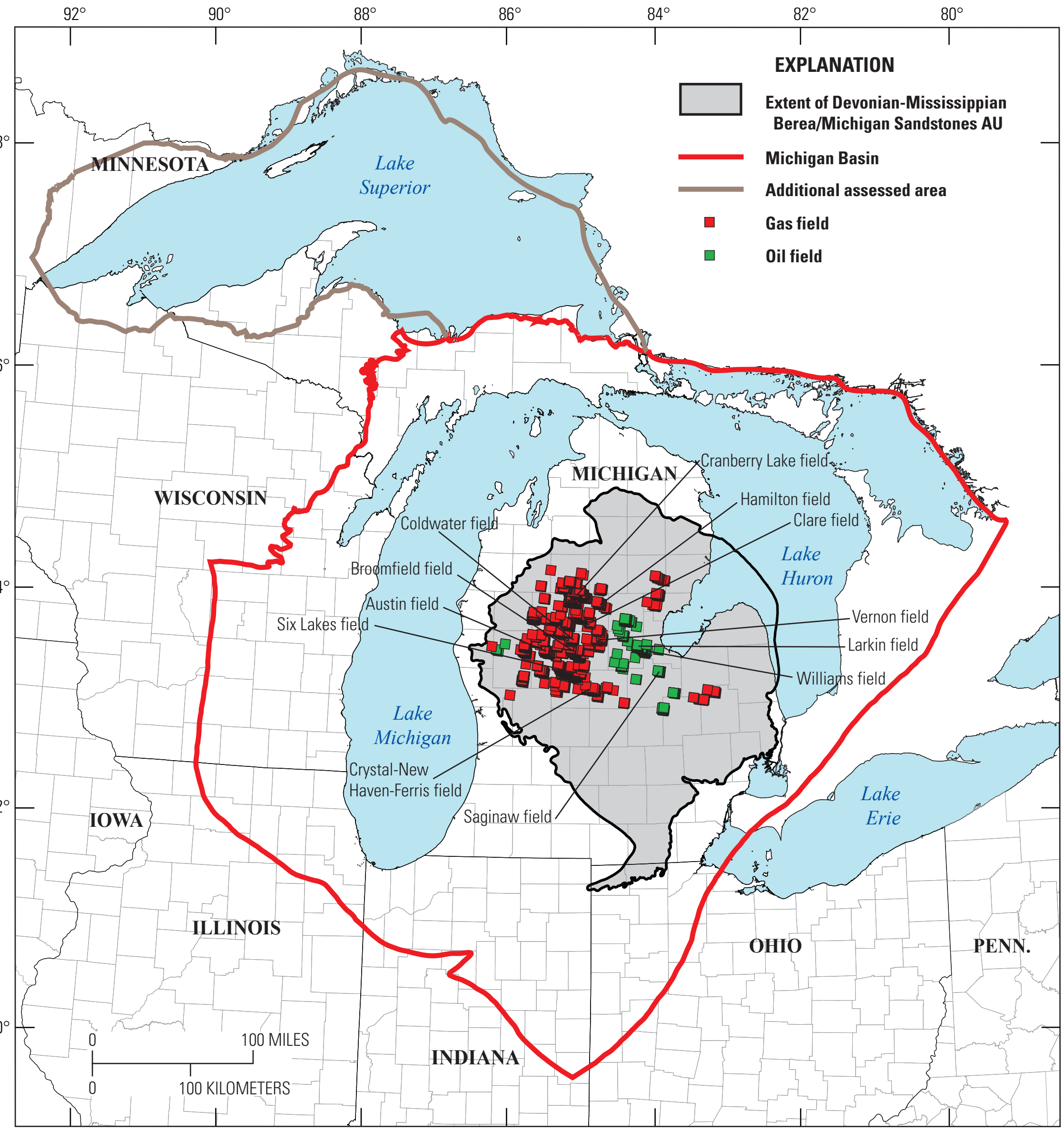
Although the Berea Sandstone contains water throughout most of the Michigan Basin, oil and gas have accumulated in reservoirs in the uppermost sandstone of the Berea Sandstone at some locations (Cohee and Landes, 1958). According to Wilson (1983) and Catacosinos and others (1990), the reservoir interval ranges from 13 to 16 ft thick, with drilling depths of about 2,500 ft. The reservoirs consist of fine-grained to very fine-grained feldspathic sandstone. In some reservoirs, porosity ranges from 13 to 26 percent (with a mean of 20 percent) based on core analysis. In other reservoirs, however, there is a considerable decrease in porosity and permeability because of secondary quartz overgrowths and the presence of ankerite cement (Gunn, 1988b). According to McCaslin (1981), many reservoirs in the Berea Sandstone are tight and require fracture treatment to stimulate production. In some reservoirs, kaolinite platelets can migrate through more permeable zones, limiting fluid flow and creating production problems. Acid treatment, however, can break down these kaolinite platelets (Gunn, 1988b). Initial production from Berea Sandstone gas wells can vary from 1 to 16 MCFG per day (Wilson, 1983).

Examples of Berea Sandstone fields include (1) Saginaw field, (2) Williams field, and (3) Larkin field (fig. 110). These three fields lie along northwest-trending anticlines that plunge to the northwest. The reservoir trap in each of these fields is an updip (southeast) pinchout of sandstone across the northwest-trending anticline. The sandstone reservoirs have primary intergranular porosity and some secondary porosity.

1. The Saginaw field (Gunn, 1988a,b) has been described by Carlson (1927), Addison (1940), and McCaslin (1981). This field was discovered in 1924; it was the first commercial oil field in Michigan. In this field, oil is found in

The base map for this figure is from Nicholson and others (2004).

Figure 109. Structure map on top of the stray sandstone of the Upper Mississippian Michigan Formation in the central part of the Michigan Basin (after Vugrinovich, 1984; Wylie, written communication, 2004).



The base map for this figure is from Nicholson and others (2004).

Figure 110. Map showing the locations of oil and gas fields where production is from reservoirs in the Devonian to Mississippian Berea/Michigan Sandstones Assessment Unit (AU) in the U.S. portion of the Michigan Basin (from U.S. Geological Survey Web site http://energy.cr.usgs.gov/oilgas/noga). Identified fields are discussed in the text.

the uppermost few feet of the Berea Sandstone. Production is at depths ranging from 1,800 to 1,860 ft from a silty fine-grained sand of low permeability. Below the pay sand, there is thin shale, and the sand underlying this shale produces water.

2. The Williams field has been described by Gunn (1988a,b) and Balthazor (1990). This field was discovered in 1980 and has produced about 2 MMBO from the Berea Sandstone as of 1990. In the Williams field, the top of the Berea Sandstone is at a depth of about 2,400 ft, and the main reservoir is sandstone that is interpreted as a delta-front deposit (Gunn, 1988a,b). Characteristics of the main pay zone are as follows: average porosity = 20 percent, average permeability = 30 md, and average thickness = 16 ft. The gas-oil ratio is less than 500 cubic ft of gas per barrel of oil.

3. The Larkin field has been described by Gunn (1988a,b). In this field, the top of the Berea Sandstone is at a depth of about 2,400 ft, and the average porosity of main pay zone is 20 percent. The reservoir interval is sandstone that is interpreted as a deltaic deposit.

Michigan Formation Stray Sandstone

In the Michigan Formation, most petroleum production has been natural gas produced from the stray sandstone, although the Michigan Formation in the Clare field (fig. 110) has produced some oil (Hard, 1938; Ball and others, 1941a,b; Cohee and Landes, 1958; Champion, 1968; Conybeare, 1976; Nowaczewski, 1994). Gas-water contacts exist within the stray sandstone reservoirs, and gas traps are both structural (anticlines) and stratigraphic. The reservoirs, ranging from 10- to 60-ft-thick gas pay zones, are thin and generally occur at depths less than 2,000 ft. There is much variability in porosity and permeability. According to Wasson (1936), the stray sandstone reservoir pressures are normal for the depths drilled. Several decades later, however, Nowaczewski (1994) stated that many of the stray sandstone fields were initially underpressured.

Examples of Michigan Formation stray sandstone fields include (1) Austin field, (2) Six Lakes field, (3) Broomfield field, and (4) the Clare field (fig. 110). The Austin field and the Six Lakes field are located on the Austin anticline, whereas the Broomfield field is located on the Broomfield anticline and the Clare field is located on the Greendale anticline.

1. The Austin field produced gas primarily from the stray sandstone, although there was also some gas production from sandstone beds higher in the stratigraphic section (Rawlins and Schellhardt, 1936; Hard, 1938; Ball and others, 1941a,b) and from the St. Peter Sandstone and Prairie du Chien Group (John Esch, written commun., April 2010). The main reservoir is a 1- by 5-mi sandstone body, with a maximum thickness of 39 ft. The depth below the surface to top of the pay zone ranges from 281 to 301 ft, and the average thickness of the pay zone is 9.6 ft. Average reservoir porosity is 17 percent, and permeability is greatest where the sandstone is thickest. The average initial reservoir pressure was 553 lb/in^2; the average initial open flow rate was 5.88 MMCFG per day per well.

2. The Six Lakes field (also called the Hinton-Millbrook-Belvidere field), produced gas and water from the base of the Michigan Formation (Rawlins and Schellhardt, 1936; Hard, 1938). The depth below the surface to top of the pay zone ranges from 1,200 to 1,300 ft, and the average thickness of the pay zone is 10.3 ft. Average reservoir porosity is 20 percent. The average initial reservoir pressure was 545 lb/in^2; the average initial open flow rate was 10 MMCFG per day per well.

3. The Broomfield field was discovered in 1930 and has produced both oil and gas from two or more sandy zones at the base of the Michigan Formation (Rawlins and Schellhardt, 1936; Hard, 1938) and oil from the Dundee Limestone and the Traverse limestone (John Esch, written commun., April 2010). In some wells, water was present in the producing intervals. The depth from the surface to top of the pay zone is approximately 1,300 ft, and the average thickness of the pay zone is 3.2 ft. Reservoir porosity ranges from 18 to 20 percent. The average initial reservoir pressure was 614 lb/in^2; the average initial open flow rate was 2.4 MMCFG per day per well.

4. The Clare field was discovered in 1929; it was the first commercial gas field in Michigan (Rawlins and Schellhardt, 1936; Hard, 1938; Newcombe, 1938). The field has produced gas (as well as heavy oil and water) from the stray sandstone and oil from the Traverse limestone (John Esch, written commun., April 2010). The average thickness of the pay zone is 4 ft; average reservoir porosity is 20 percent. The average initial reservoir pressure was 635 lb/in^2; average initial open flow rate was 3.0 MMCFG per day per well.

Michigan Formation

Several fields in the Michigan Basin produce petroleum from both the Michigan Formation and from the underlying Middle Devonian carbonate strata. All of these fields are located on northwest-trending anticlines in central Michigan. Examples of these fields include (1) Coldwater field, (2) Vernon field, (3) Cranberry Lake field, (4) Hamilton field, and (5) Crystal-New Haven-Ferris field (fig. 110).

1. Coldwater field was discovered in 1944 in Isabella County, Michigan, and has produced mostly oil from the Rogers City Member of the Dundee Limestone, although some gas has been produced from the Michigan Formation stray sandstone (Wolcott, 1948; Harrison and others, 1993). In this field, the reservoir interval in the Michigan Formation has a productive area of 2,400 ft^2 and is located at an average depth of 1,400 ft below the surface.

2. Vernon field was discovered in April 1930 and is located on the Greendale anticline in Isabella County, Michigan, and initially produced oil from the Dundee Limestone (Rawlins and Schellhardt, 1936; Hard, 1938). Later, in October 1930, this field initiated gas production (along with heavy oil and water) from the Michigan Formation stray sandstone.

3. Cranberry Lake field was discovered in 1943 in Clare County, Michigan, and initially produced gas at a depth of 1,300 ft from the Michigan Formation stray sandstone (Wilson and others, 1976a). The gas field was fully developed and then later converted to a gas storage field. Wells were deepened later and gas was subsequently produced from the underlying Traverse limestone and Dundee Limestone.

4. Hamilton field was discovered in 1940 in Clare County, Michigan, and initially produced gas at a depth of about 1,500 ft from the Michigan Formation and Marshall Sandstone (Wilson and others, 1976b). After the gas interval was developed, it was converted to a gas storage reservoir called the North Hamilton field. In 1940, oil was discovered at the Hamilton field in the Dundee Limestone at a depth of about 4,050 ft. In 1952, oil was also discovered in the Devonian Richfield Member of the Lucas Formation (Detroit River Group) at a depth of about 5,150 ft.

5. Crystal-New Haven-Ferris field was discovered in 1935 in Montcalm and Gratiot Counties, Michigan, and has produced mostly oil from the Dundee Limestone. Some gas has been produced from the lower part of the Michigan Formation and (or) the upper part of the Marshall Sandstone (Rawlins and Schellhardt, 1936; Hake, 1938; Hard, 1938).

Petroleum Geochemistry

A gas chromatogram of the saturated-hydrocarbon fraction of oil produced from the Traverse Group in the Peacock field, Lake County, Michigan, shown in figure 90**,** is characteristic of oil with an Antrim Shale source. This saturated-hydrocarbon distribution is characterized by a slight odd-even-carbon predominance. The carbon preference index (CPI, modified from Bray and Evans, 1961) between n-C_{20} and n-C_{26} is 1.03, the pristane/phytane ratio is approximately 1.9, and the pristane/n-C_{17} ratio is approximately 3.1 (all values are from measurements of peak height). The hydrocarbon distribution shown in figure 90 is very similar to gas chromatographic signatures of Traverse Group oils illustrated in Illich and Grizzle (1983, 1985).

Natural gas production from Berea Sandstone reservoirs is primarily from fields on the southwest (Muskegon and Ottawa Counties), southeast (Genesse and Lapeer Counties), and northeast (Arenac and Ogemaw Counties) margins of the central basin. Depths to these reservoirs range from 1,080 to 1,510 ft. Natural gas production from Michigan Formation reservoirs is primarily from the western part of the central basin (for example, Missaukee, Clare, Isabella, Gratiot, Osceola, Mecosta, and Montcalm Counties). Depths to these reservoirs range from 870 to 1,610 ft.

The chemical compositions (N_2 mole percent, CO_2 mole percent, H_2S mole percent, ethane/isobutane mole percent/mole percent, and gas wetness percent) of 15 Berea Sandstone gas samples are summarized in table 13; 44 Michigan Formation gas samples are summarized in table 14. The data summarized in tables 13 and 14 are from Moore and Sigler (1987), Hamak and Sigler (1991), and the data set, Michigan Oil and Gas Well Gas Analyses Data from the Michigan Geological Repository for Research and Education at Western Michigan University (http://wsh060.westhills.wmich.edu/MGRRE/data/). The data in the geographic distribution plots shown in figures 111, 112, 113, and 114 are also from these data sets.

Defining chemical characteristics of natural gases produced from the Berea Sandstone and the Michigan Formation reservoirs includes intermediate gas wetness (median = 14 percent and 16 percent, respectively), relatively high N_2 contents (median = 21 and 9.1 mole percent, respectively) low CO_2 contents (median = 0.10 and 0.14 mole percent, respectively), low H_2S contents (medians both <0.01 mole percent), and very high ethane/isobutane mole percent/mole percent ratios (median = 38 and 46, respectively). Geographic distributions of N_2, CO_2, and H_2S contents and gas wetness are shown in figures 111, 112, 113, and 114.

Nitrogen contents of natural gases are highest in Berea Sandstone reservoirs on the margins of the central basin (fig. 111). A comparison of the geographic distribution of nitrogen contents in gases with the organic-matter thermal-maturity map in figure 102 shows that nitrogen contents of natural gases are lower in the western part of the central basin area where organic matter in the Antrim Shale is thermally mature. The correlation of higher N_2 contents in gas with lower organic matter thermal maturities is similar to that observed for Niagara Group reef reservoirs (figs. 66 and 67). The geographic distributions of CO_2 and H_2S contents show no apparent regional variations (figs. 112 and 113). For gas samples from most Berea Sandstone and Michigan Formation reservoirs, gas wetness is consistently between 10 and 20 percent (fig. 114). However, in all Michigan Formation stray sandstone fields in the area of greatest Antrim Shale thermal maturity in the western part of the central basin (Osceola, Clare, Mecosta, Isabella, and Newyago Counties), gas wetness shows a much wider range, with gas wetness for production from seven fields less than 10 percent and gas wetness for four other fields greater than 20 percent.

Petroleum generated from organic matter in the Antrim Shale and Ellsworth Shale may not have migrated far either vertically or horizontally. This conclusion is indicated by the geographic distribution of Michigan Formation reservoirs (mostly gas), which occur primarily in the western part of the central basin where organic matter in the Antrim Shale is thermally mature (fig. 102). The occurrence of lower gas N_2 contents in the western part of the central basin supports this hypothesis (fig. 111).

Table 13. Statistical summary of the chemical compositions of 15 natural gas samples collected from wells producing from the Upper Devonian Berea Sandstone primarily in Arenac, Genesee, Lapeer, Muskegon, and Ogemaw Counties in central Michigan. Ethane/isobutane (mole percent/mole percent) was calculated for the six samples where isobutane content was >0.01 mole percent.

[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	15	15	15	6	15
Median	21	0.10	<0.01	38	14
Average, Standard deviation	19 ± 7.4	0.14± 0.17	<0.01± 0.01	39 ± 11	15 ± 4.7
Range	1.7–29	<0.01–0.57	<0.01–1.3	25–58	9.4–24

Table 14. Statistical summary of the chemical compositions of 44 natural gas samples collected from wells producing from the Upper Mississippian Michigan Formation primarily from Clare, Isabella, Mecosta, Missaukee, and Montcalm Counties in central Michigan. Ethane/isobutane (mole percent/mole percent) was calculated for the eight samples where isobutane content was >0.01 mole percent.

[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

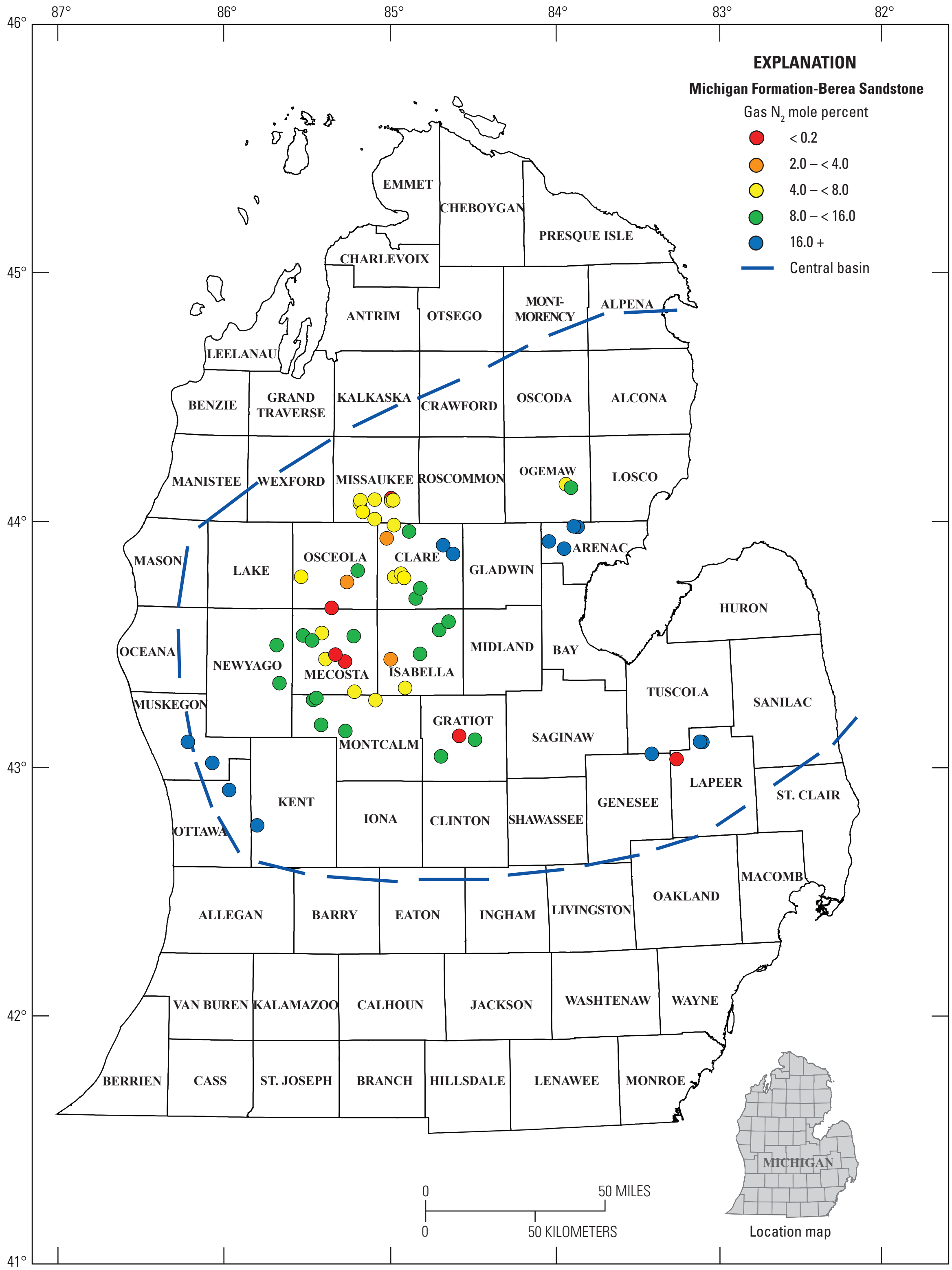
Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	44	44	44	8	44
Median	9.1	0.14	<0.01	46	16
Average, Standard deviation	9.2± 4.8	0.23± 0.27	0.07 ± 0.28	44 ± 15	15 ± 5.2
Range	<0.01–26	<0.01–1.4	<0.01–1.3	19–63	1.9–26

Undiscovered Petroleum Resources

In the 2004 assessment of the U.S. portion of the Michigan Basin, the USGS assessed the Devonian to Mississippian Berea/Michigan Sandstones AU as a conventional petroleum accumulation. The assessment unit was considered to be primarily gas-prone, but the undiscovered fields were estimated to include both oil fields and gas fields. For the oil fields, the estimated volumes of undiscovered, technically recoverable oil resources are 2.0 MMBO at the 95-percent certainty level, 5.0 MMBO at the 50-percent certainty level, 9.8 MMBO at the 5-percent certainty level, and a mean of 5.3 MMBO. For the associated natural gas, the estimated volumes are 0.9 BCGF at the 95-percent certainty level, 2.4 BCFG at the 50-percent certainty level, 5.2 BCFG at the 5-percent certainty level, and a mean of 2.6 BCFG. For the associated natural gas liquids, the estimated volumes are 0.03 MMBNGL at the 95-percent certainty level, 0.1 MMBNGL at the 50-percent certainty level, 0.2 MMBNGL at the 5-percent certainty level, and a mean of 0.1 MMBNGL (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).

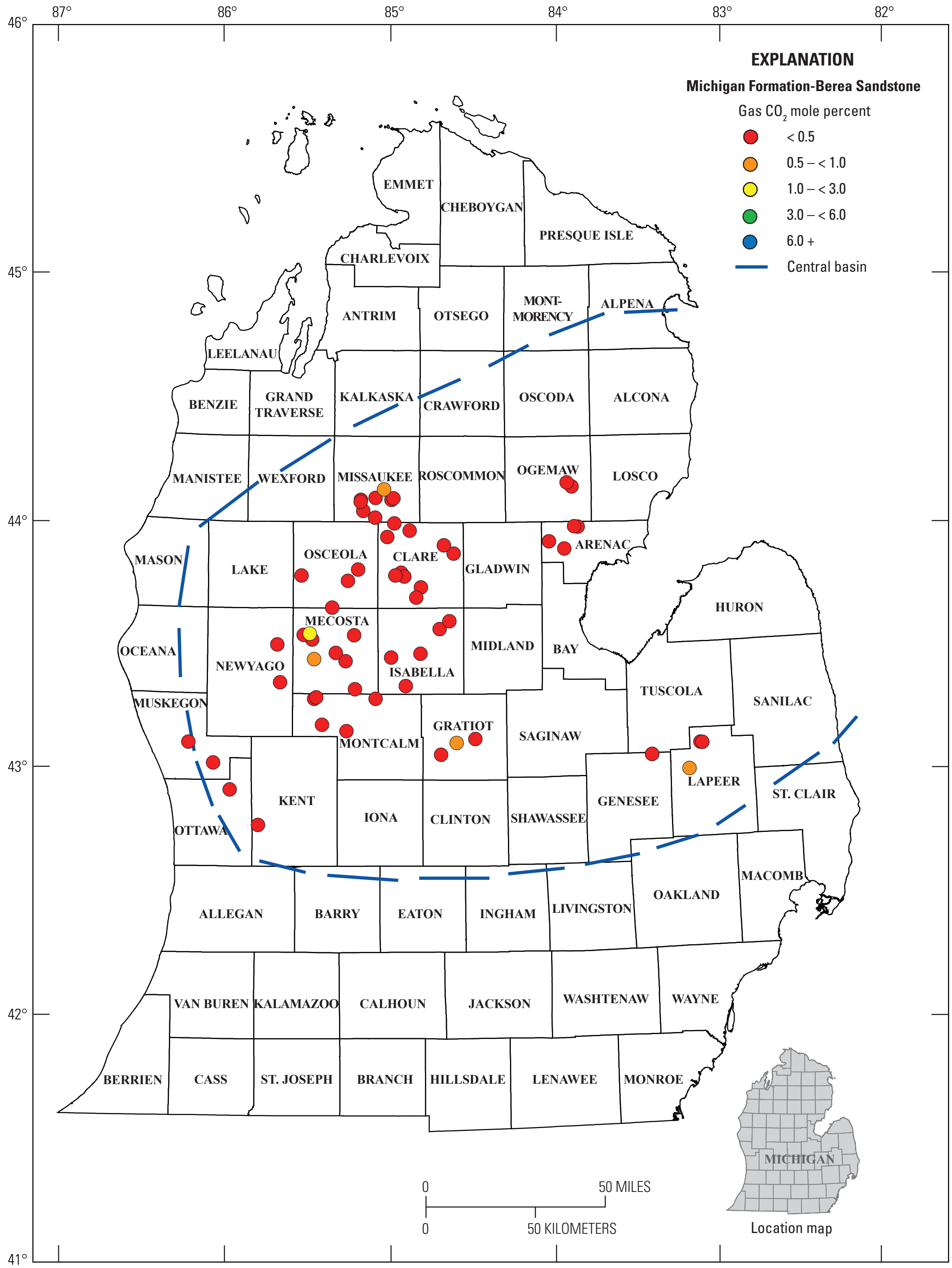
For the gas fields, the estimated volumes of undiscovered, technically recoverable natural gas resources are 11.4 BCGF at the 95-percent certainty level, 31.8 BCFG at the 50-percent certainty level, 66.9 BCFG at the 5-percent certainty level, and a mean of 34.6 BCFG. For natural gas liquids, the estimated volumes are 0.4 MMBNGL at the 95-percent certainty level, 1.2 MMBNGL at the 50-percent certainty level, 2.8 MMBNGL at the 5-percent certainty level, and a mean of 1.4 MMBNGL (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).

For the assessment calculations, a minimum grown field size of 0.5 MMBO equivalent was used for oil fields, and a minimum grown field size of 3 BCFG was used for gas fields. As of 2004, the Devonian to Mississippian Berea/Michigan Sandstones AU contained 2 known oil fields and 18 known gas fields with grown field sizes exceeding the minimum sizes. Also as of 2004, the assessment unit was estimated to have produced a cumulative of 13 MMBO and 233 BCFG in Michigan (figs. 9 and 10). The estimated numbers of undiscovered accumulations greater than the minimum grown field size are as follows: minimum = 1 oil accumulation and 1 gas accumulation, mode = 1 oil accumulation and 3 gas accumulation, and



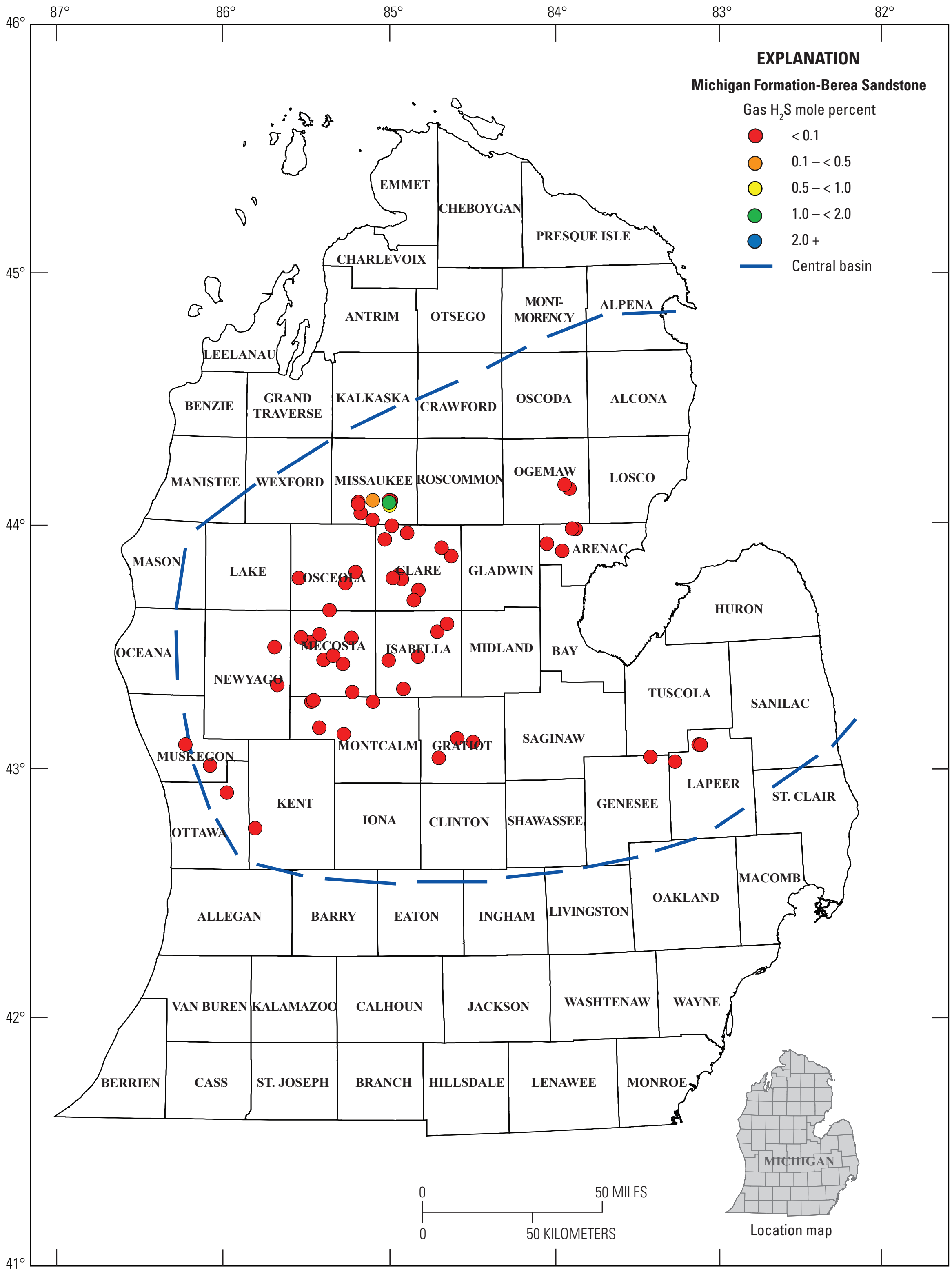
The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 111. Map showing the geographic distribution of nitrogen (N_2) contents (mole percent) for 59 natural gas samples collected from wells producing from the Upper Devonian Berea Sandstone and the Upper Mississippian Michigan Formation in the central part of the Michigan Basin.



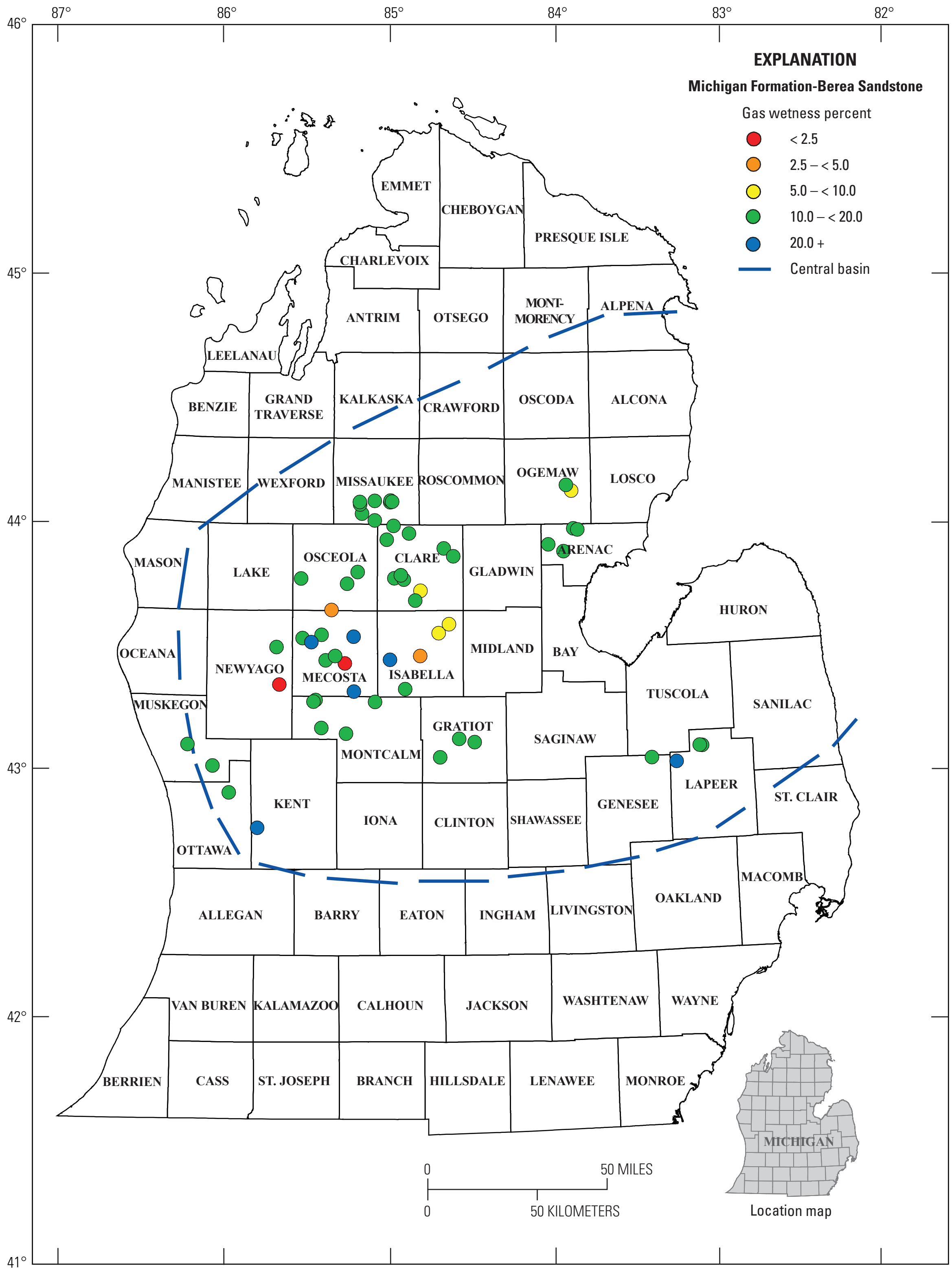
The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 112. Map showing the geographic distribution of carbon dioxide (CO_2) contents (mole percent) for 59 natural gas samples collected from wells producing from the Upper Devonian Berea Sandstone and the Upper Mississippian Michigan Formation in the central part of the Michigan Basin.



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 113. Map showing the geographic distribution of hydrogen sulfide (H_2S) contents (mole percent) for 59 natural gas samples collected from wells producing from the Upper Devonian Berea Sandstone and the Upper Mississippian Michigan Formation in the central part of the Michigan Basin.



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 114. Map showing the geographic distribution of gas wetness (percent) for 59 natural gas samples collected from wells producing from the Upper Devonian Berea Sandstone and the Upper Mississippian Michigan Formation in the central part of the Michigan Basin. Gas wetness percent = 100 × (1–[C_1 mole percent /ΣC_1–C_5 mole percent]).

maximum = 3 oil accumulations and 10 gas accumulations. The sizes of undiscovered accumulations greater than the minimum grown field size were estimated as follows: minimum = 0.5 MMBO and 3 BCFG, median = 3 MMBO and 6 BCFG, and maximum = 10 MMBO and 50 BCFG.

Devonian Antrim Shale Total Petroleum System

The Devonian Antrim Shale TPS contains one petroleum source-rock interval and one petroleum assessment unit, the Devonian Antrim Shale Continuous Gas AU. The petroleum source rocks for this assessment unit consists of organic-matter-rich beds within both the Antrim Shale and the partly laterally equivalent Ellsworth Shale. Within these units, the primary organic-matter-rich shale intervals are in the Norwood and the Lachine Members of the Antrim Shale (fig. 99). Both of these members are in the lower part of the Antrim Shale. There is an additional organic-matter-rich shale (unnamed) at the top of the Antrim Shale (fig. 99). The Antrim Shale ranges in thickness from about 100 to 600 ft and the Ellsworth Shale ranges from about 200 to 800 ft thick (figs. 95 and 96). Elevations at the base of the Antrim Shale range from about 500 ft above sea level in both the southern and northern parts of the basin to more than 2,000 ft below sea level in the central part (fig. 97). The Antrim Shale consists primarily of black and gray shale; the Ellsworth Shale also consists primarily of shale, although, in the western part of the basin, the Ellsworth Shale contains some beds of fine-grained sandstone and dolomite.

In figure 102**,** R_o percent and SCI measures show that on the basin margin, organic matter in the Antrim and Ellsworth Shales is thermally immature to marginally mature; in the central part of the basin, the organic matter is thermally mature (within the oil window). On the basin margins, very little thermogenic petroleum has been generated; however, organic matter in both the Antrim Shale and the Ellsworth Shale in the immature and marginally mature areas are source rocks for biogenic gas. This biogenic gas is the primary petroleum type in the Devonian Antrim Shale Continuous Gas AU. At present the known economic quantities of gas in the Devonian Antrim Shale Continuous Gas AU are restricted to the northern part of the basin.

Devonian Antrim Shale Continuous Gas Assessment Unit

The Devonian Antrim Continuous Gas AU consists of shales of the Antrim Shale and the partly laterally equivalent Ellsworth Shale (fig. 98). The stratigraphic relations of these two formations are described in greater detail in the section Ordovician to Devonian Composite Total Petroleum System III. The Antrim and Ellsworth Shales are both the petroleum source rocks and the reservoir rocks, and thus the outline of the petroleum source rock is identical to the outline of the Devonian Antrim Shale Continuous Oil AU (figs. 95 and 96).

The Antrim Shale, which ranges in thickness from 100 to 600 ft throughout much of its extent (fig. 95), consists primarily of black and gray shale. The black shale members are the Norwood and Lachine Members of the Antrim Shale. Organic carbon content in the Norwood and Lachine Members ranges from 0.5 to 24 weight percent (Martini and others, 1998). The Ellsworth Shale, which ranges in thickness from 200 to 800 ft throughout much of its extent (fig. 96), consists primarily of gray and green shale. In addition, the Ellsworth Shale contains some beds of fine-grained sandstone and dolomite in the western part of the basin.

Assessment Unit Model

The Devonian Antrim Continuous Gas AU is a continuous “unconventional” petroleum accumulation. Petroleum production from the Devonian Antrim Continuous Gas AU consists of gas, and the petroleum source rocks are the shale beds of the Antrim and Ellsworth Shales (predominantly the Norwood and Lachine Members of the Antrim Shale). In the northern part of the Michigan Basin, most (>80 percent) of the Antrim Shale gas is of microbial origin, although some (<20 percent) of the gas is of thermogenic origin (Martini and others, 1996, 1998). The origin of the biogenic gas in the Antrim Shale is associated with Pleistocene ice sheet advances and retreats, which reopened preexisting fractures and forced a large influx of fresh water into the subsurface. This influx of fresh water stimulated bacterial activity that produced methane (Martini and others, 1996, 1998; Walter and others, 1999). In contrast, the minor amounts of thermogenic gas in the Antrim Shale was generated in the central part of the basin during Pennsylvanian to Early Triassic as the shale was buried by siliciclastic sediments of the Alleghanian orogeny. Most of the biogenic gas remains near its area of generation, although some migration of the thermogenic gas may have occurred since maximum burial during Pennsylvanian to Early Triassic.

No discrete fields with fluid contacts are recognized for Antrim Shale gas production (Curtis, 2002), although most current production is confined to the Norwood and Lachine Members in the lower part of the Antrim Shale. Within the Antrim Shale, the shale itself acts as both reservoir traps and seals. Gas is adsorbed by clays and organic matter within the shale, dissolved in bitumen, and stored in interparticle porosity and in fractures (Cain and others, 1995). Gas is also trapped by fractures induced by ice-sheet loading and unloading and may be trapped by the overlying Quaternary glacial till (Martini and others, 1996, 1998). In some instances, gas trapping may also be controlled at least partially by hydrodynamic flow and water block at the subcrop (Maness and others, 1993).

Devonian Antrim Shale Continuous Gas AU encompasses the entire extent of the Antrim and Ellsworth Shales in the Michigan Basin. Within this assessment unit, however, the area having potential for additions to reserves is restricted to the northern part of the basin (figs. 115 and 116). The southern boundary of the area having potential for additions to reserves (blue line on fig. 116) is very sharp, although it is not certain what geologic variables control the location of this boundary. Antrim Shale to the north of this southern boundary (blue line on fig. 116) contains economic concentrations of biogenic gas, extensive and dense fracture networks, and formation waters with lower salinity concentrations (McIntosh and others, 2002, 2011; Martini and others, 2003; McIntosh and Martini, 2008). South of this boundary (blue line on fig. 116), the Antrim Shale contains noneconomic concentrations of biogenic gas, fewer and less extensive fracture networks, and formation waters with greater salinity concentrations (McIntosh and others, 2002, 2011; Martini and others, 2003; McIntosh and Martini, 2008). Furthermore, the southern boundary of this area having potential for additions to reserves is apparently not controlled by temperature (D. Hayba, oral commun., 2005). Martini and others (1998) and McIntosh and Martini (2008) have proposed that this southern boundary is governed by formation-water salinity.

According to Martini and others (1998), most formation waters in the Michigan Basin are bromine-rich calcium chloride ($CaCl_2$)-type brines. In contrast, formation waters in the Antrim Shale are a mixture of bromine-rich $CaCl_2$-type brines, bromine-poor brines, and meteoric water. The bromine-rich $CaCl_2$-type brines are derived from brines from the underlying Traverse Group carbonate strata, whereas the bromine-poor brines are derived from halite dissolution (halite within the Detroit River Group or within Silurian strata). The meteoric water is derived from glacial meltwater and (or) modern recharge; calculated age of the glacial meltwater is 21,000 ^{14}C years before present; age of the modern recharge is 2,000 ^{14}C years before present. The measurable chemical effects of meteoric-water recharge extend about 30 mi southward toward the basin center from the location where the Antrim Shale is in direct contact with the overlying Pleistocene glacial till.

Reservoir Characteristics

Shales in most areas in the Devonian Antrim Continuous Gas AU have produced gas; economic gas production, however, is apparently limited to the northern part of the basin (figs. 115 and 116). In this region, there exist some nonproductive areas where bedrock valleys are cut into the Antrim Shale. The more gas-productive areas occur where the shale is greatly fractured. In the primary Antrim Shale production area of northern Michigan, fractures trend northeast and northwest (Holst and Foote, 1981; Richards and others, 1994; Martini and others, 1998). The northeast fracture trend is the primary fracture direction. Furthermore, fractures are more pervasive and fracture widths are greater in the black shale members (Norwood and Lachine Members) than the other members of the Antrim Shale.

There are several difficulties with regards to obtaining precise per-well production data from Antrim Shale reservoirs, primarily because most data are reported for a given lease block rather than from individual wells. Furthermore, some lease areas contain single wells, whereas other lease areas contain multiple wells. Nevertheless, most pressure data indicate that reservoirs in the Antrim Shale range from underpressured to normally pressured (Moore and Sigler, 1987). According to Curtis (2002), most Antrim reservoirs occur at depths ranging from 600 to 2,400 ft, with a gross reservoir thickness of 160 ft and net reservoir thickness ranging from 70 to 120 ft.

Prevailing thought is that there are no dry holes in the primary Antrim Shale production area of northern Michigan; however, 10 to 20 percent of the wells in this area produce less than 10 MCFG per day (and are thus not economic), and productivity within a given lease area may vary greatly. For example, in one lease area, a well produced 10 MCFG per day and another well 0.25 mi away produced 300 MCFG per day. Gas production from the Antrim Shale is associated with large volumes of produced water, with initial volumes from a typical well of more than 1,000 barrels of water per day. A survey by C. Swezey of various operators in the basin indicates that the maximum well performance of an Antrim well is thought to be about 1 MMCFG per day. Curtis (2002) estimated that the average Antrim Shale well in the northern Michigan Basin produced 116 MCFG per day with 30 bbl of water per day. A more recent estimate by Hunter (2007) is that average gas production from the Antrim Shale, as of March 2007, was 41 MCFG per day per well. According to data from the Michigan Public Service Commission, gas production from the Antrim Shale peaked in 1998.

Petroleum Geochemistry

The chemical compositions (N_2 mole percent, CO_2 mole percent, H_2S mole percent, ethane/isobutane mole percent/mole percent, and gas wetness percent) of 195 natural gas samples from the Antrim Shale (Antrim Shale Group A) in the northern part of Michigan (Otsego, Montmorency, Oscoda, and Manistee Counties) are summarized in table 15. The chemical compositions of 36 other natural gas samples from the Antrim Shale (Antrim Shale Group B) from Otsego County, Michigan, are summarized in table 16. The data summarized in tables 15 and 16 are from Moore and Sigler (1987), Hamak and Sigler (1991), and two data sets, Michigan Oil and Gas Well Gas Analyses Data and Michigan Public Service Commission MichCon "TIPS" Data from the Michigan Geological Repository for Research and Education at Western Michigan University (http://wsh060.westhills.wmich.edu/MGRRE/data/). The data in the geographic distribution plots shown in figures 117 and 118, and the data plots shown in figures 119 and 120 are also from these data sets.

Average gas wetness for the samples in table 15 is 1.1 percent, whereas average gas wetness for the samples in table 16 is 4.2 percent. The gases in both data sets have relatively high contents of CO_2 and relatively low contents of N_2. The average ethane/isobutane ratio is 39 for 30 of the 195 gas samples summarized in table 15, whereas the average ethane/isobutane ratio is 8.7 for 22 of the 36 gas samples summarized in table 16.

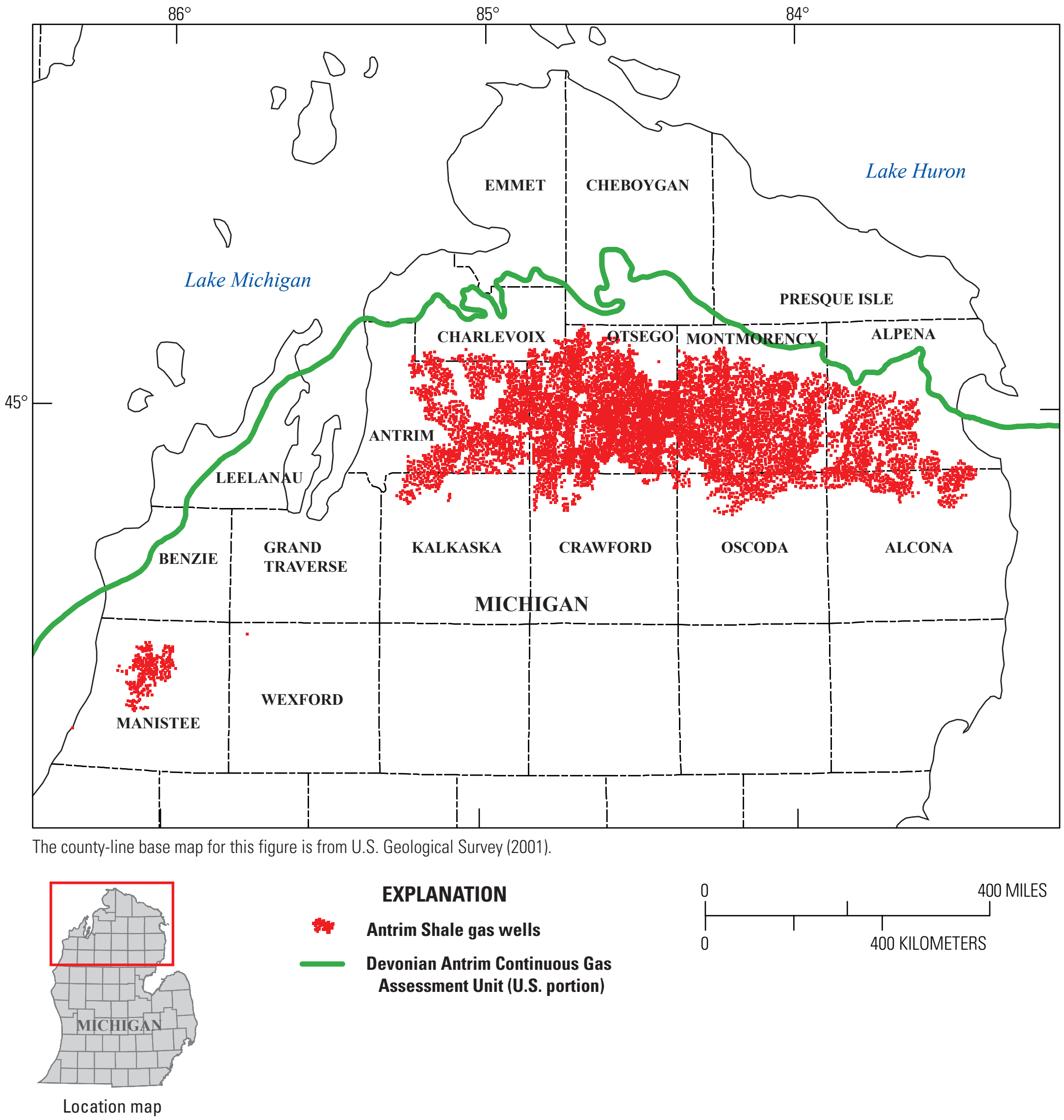


Figure 115. Map showing locations of natural gas wells producing from the Upper Devonian Antrim Shale in northern Michigan. Data are from the Michigan Department of Environmental Quality. Data compiled by Attanasi and others (2006) and Coburn and others (2012).

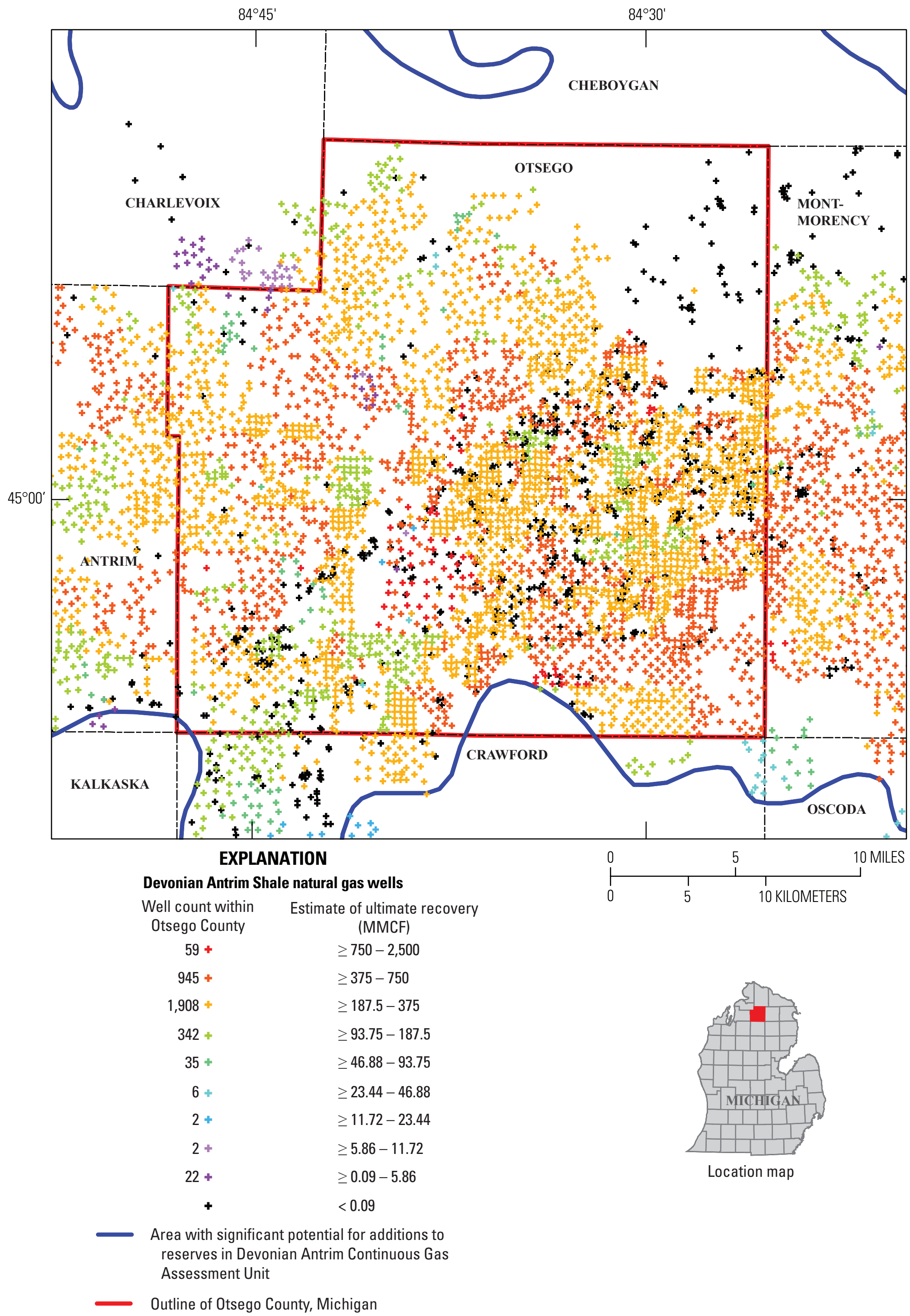


Figure 116. Map of estimated ultimate recovery of gas resources for natural gas wells producing from the Upper Devonian Antrim Shale in Otsego County, Michigan. Data are from the Michigan Department of Environmental Quality. Data compiled by Attanasi and others (2006) and Coburn and others (2012). MMCF, million cubic feet.

Within the Antrim Shale production area in northern Michigan, the depth to the Antrim Shale generally increases toward the south (fig. 117). There is also a minor increase in gas wetness toward the south; that is, there is a minor increase in the amounts of higher carbon-number gases (C_2 and greater) (fig. 118). This trend has been interpreted as a result of an increased contribution of thermogenic gases toward the center of the basin (Martini and others, 1996, 1998).

Figure 119 shows a graph of gas wetness versus ethane/isobutane for the two groups of Antrim Shale gas samples (Antrim Shale A and B) summarized in tables 15 and 16, respectively. For comparison, gas samples from reservoirs in the central part of the northern Silurian reef trend in Otsego and Crawford Counties are also shown. The graph suggests that the gases summarized in table 16 (Antrim Shale B samples from Otsego County, Michigan) contain a component of gas from the underlying Niagara Group reef trend. In other words, it appears that gas from the reef reservoirs has migrated upsection and into the Antrim Shale in Otsego County. In support of this interpretation, the average H_2S content of the 46 gas samples from the Niagara Group and Salina Group reservoirs plotted in figure 119 is 0.75 mole percent, which is within the range of H_2S contents (<0.01–0.79 mole percent) reported for the gases produced from the Antrim Shale in Otsego County (table 16).

Compared to most other gases produced in the Michigan Basin, the average CO_2 content of Antrim Shale gas is relatively high (21 ± 7.2 mole percent, table 15). Furthermore, CO_2 contents of Antrim Shale produced gases appear to increase with time since well completion (fig. 120). Although there is considerable scatter in the data, Antrim Shale gas generally has 0 to 5 mole-percent CO_2 during the first year after well completion, 15 to 20 mole-percent CO_2 at 60 months after well completion, and reaches about 25 mole-percent CO_2 at 240 months after well completion. This trend of increasing CO_2 content could be the result of various factors, including the relative contribution of thermal gases, the CO_2 contents of dissolved gases following methanogenesis, the relative rates of release of CO_2 and CH_4 from shale microporosity during gas desorption, and the relative area of the Antrim Shale produced by a well. Additional data on CO_2 content for Antrim Shale gas samples are given in Martini and others (1998), although these data are not plotted in figure 120 because sampling dates are not given.

Undiscovered Petroleum Resources

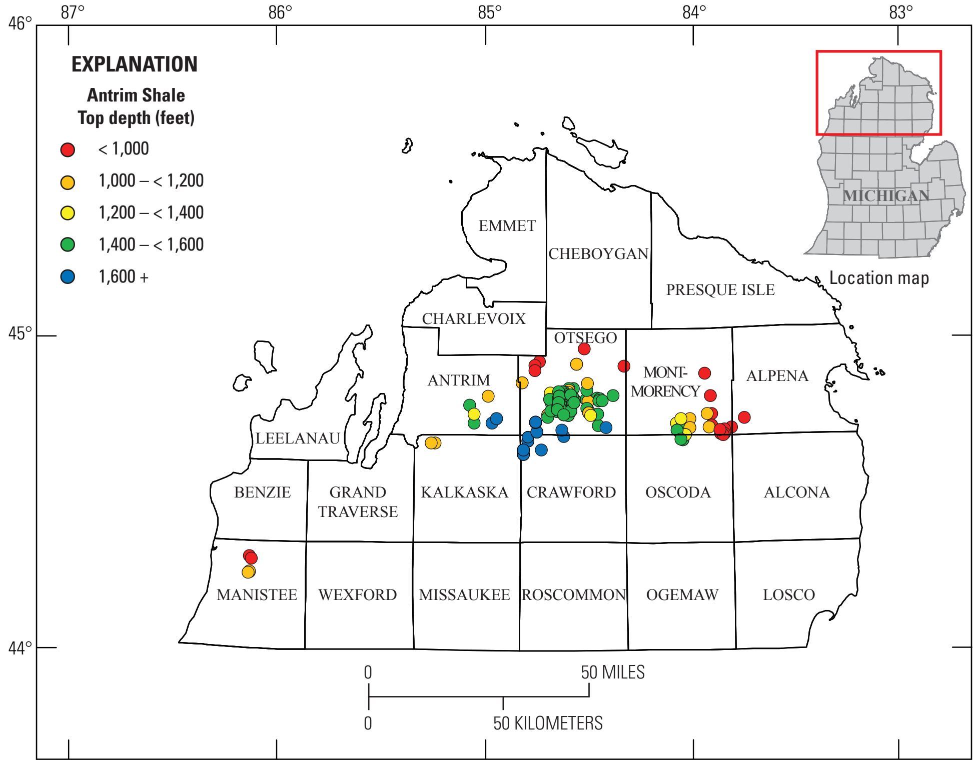
For the 2004 assessment of undiscovered, technically recoverable oil and gas resources of the U.S. portion of the Michigan Basin, the USGS assessed the Devonian Antrim Continuous Gas AU as a continuous (or "unconventional") petroleum accumulation. The assessment unit was considered to contain only gas. For the gas fields, the estimated volumes of undiscovered, technically recoverable natural gas resources are 5.48 TCGF at the 95-percent certainty level, 7.36 TCFG at the 50-percent certainty level, 9.87 TCFG at the 5-percent certainty level, and a mean of 7.48 TCFG (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).

For the assessment calculations, cumulative gas production from the Devonian Antrim Shale Continuous Gas AU (as of 2004) was estimated to be approximately 1,879 BCFG in the State of Michigan (figs. 9 and 10). The total assessment area was considered to be the U.S. portion of the area shaded in gray in figure 95. Much of this area has already been tested by existing wells. Of the untested assessment area, only a small percentage (minimum = 2 percent, mode = 3.5 percent, and maximum = 5 percent) of the area was considered to have potential for additions to reserves. Within the area having potential for additions to reserves, each well was assumed to drain a variable area that is called a cell. For untested cells having potential for additions to reserves, cell size was estimated as minimum = 20 acres, mode = 80 acres, and maximum = 160 acres. The total recovery per cell (for untested cells having potential for additions to reserves) was estimated as minimum = 0.02 BCFG, median = 0.04 BCFG, and maximum = 10 BCFG.

Pennsylvanian Saginaw Total Petroleum System

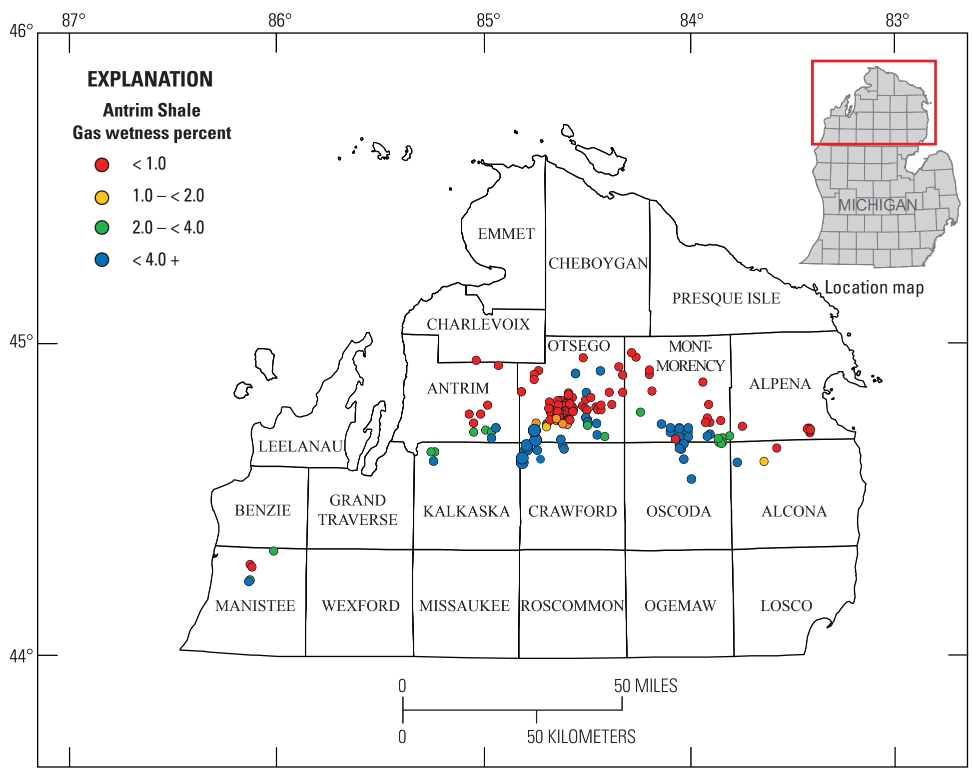
The Pennsylvanian Saginaw TPS consists of one petroleum source rock lithology and one petroleum assessment unit. The potential petroleum source rocks are coal beds within the Saginaw Formation, and the assessment unit is the Pennsylvanian Saginaw Coal Bed Gas AU. The Saginaw Formation coal beds are restricted to the central part of the Michigan Basin.

The stratigraphic nomenclature for the Pennsylvanian strata in the Michigan Basin changed significantly from the early classifications by Lane (1902) and Cooper (1906) (fig. 121) to the later classifications of Wanless and Shideler (1975) and Vugrinovich (1984). Wanless and Shideler (1975 divided the Saginaw Formation into a lower part ("Interval A") and an upper part ("Interval B") (see fig. 121). Interval A includes the Parma Sandstone Member and the Saginaw Coal Bed; Interval B includes the Verne Coal Bed and the Verne Limestone Member. According to both Wanless and Shideler (1975) and Vugrinovich (1984), the Saginaw Formation rests on an unconformity that caps the underlying Mississippian Bayport Limestone, and the Saginaw Formation is capped by an unconformity above which lies the Pennsylvanian Grand River Formation or younger strata. These younger strata consist of scattered patches of white to yellow to gray sandstone (Grand River Formation) and (or) unconsolidated to poorly consolidated red siliciclastic sediments and gypsum. These red siliciclastic sediments and gypsum have been identified by some as the Middle Jurassic Ionia Formation (Cross, 1998, 2001; Dickinson and others, 2010a,b), whereas others have identified them as Pennsylvanian-age strata (Kelly, 1936; Benison and others, 2011). These red siliciclastic sediments and gypsum are overlain, in turn, by Quaternary glacial sediments that range in thickness from a few feet to more than 1,300 ft.



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 117. Map showing depths (in feet) from the surface to the top of the Devonian Antrim Shale in 225 producing wells in northern Michigan. Depth data are from the Michigan Department of Environmental Quality Online Oil and Gas Information System, accessible at: http://ww2.deq.state.mi.us/mir/.



The county-line base map for this figure is from U.S. Geological Survey (2001).

Figure 118. Map showing the geographic distribution of gas wetness (percent) values for 36 natural gas samples collected from wells producing from the Devonian Antrim Shale in northern Michigan. Gas wetness percent = 100 × (1– [C_1 mole percent/ΣC_1–C_5 mole percent]).

Table 15. Statistical summary of the chemical compositions of 195 natural gas samples (Antrim Shale Group A) collected from wells producing from the Upper Devonian Antrim Shale from Manistee, Montmorency, Oscoda, and Otsego Counties in northern Michigan. Ethane/isobutane (mole percent/mole percent) was calculated for the 30 samples where isobutane content was >0.01 mole percent.

[*Wetness (percent) = 100 × (1− [C_1 mole percent/ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	195	195	19	30	195
Median	0.23	22	<0.01	33	0.5
Average, Standard deviation	0.59 ± 1.3	21 ± 7.2	<0.01 ± <0.01	39 ± 21	1.1 ± 1.6
Range	<0.01–14	<0.01–35	<0.01–0.01	13–86	<0.01–8.6

Table 16. Statistical summary of the chemical compositions of 36 natural gas samples (Antrim Shale Group B) collected from wells producing from the Upper Devonian Antrim Shale from Manistee, Oscoda, and Otsego Counties in northern Michigan. Ethane/isobutane (mole percent/mole percent) was calculated for the 22 samples where isobutane content was >0.01 mole percent.

[*Wetness (percent) = 100 × (1− [C_1 mole percent /ΣC_1–C_5 mole percent]); n, number]

Statistic	Nitrogen (mole percent)	Carbon dioxide (mole percent)	Hydrogen sulfide (mole percent)	Ethane/isobutane (mole percent/ mole percent)	*Wetness (percent)
Observations (n)	36	36	14	22	36
Median	0.26	24	<0.01	8.3	0.83
Average, Standard deviation	0.41 ± 0.48	19 ± 12	0.06 ± 0.21	8.7 ± 2.6	4.2 ± 6.4
Range	<0.01–2.1	<0.01–33	<0.01–0.79	4.5–13	0.2–24

Most of the lower part of the Saginaw Formation ranges from 200 to 400 ft in thickness (fig. 122); most of the upper part of the Saginaw Formation is less than 100 ft thick (fig. 123). In most places, the base of the Saginaw Formation ranges from 200 ft above sea level to 200 ft below sea level (fig. 124). Within the Saginaw Formation, individual coal beds are less than 3 ft thick; drilling depths to the coal beds are less than 800 ft.

Pennsylvanian Saginaw Coal Bed Gas Assessment Unit

The Pennsylvanian Saginaw Coal Bed Gas AU consists of coal beds within the Pennsylvanian Saginaw Formation (fig. 121). The Saginaw Formation consists of shale, siltstone, sandstone, and coal, with some minor limestone and calcareous shale (Briggs, 1968). The Saginaw Formation coal beds have not been buried deeply enough for the organic matter to have reached thermal maturity, and thus there is a very low possibility of any thermogenic petroleum originating in this stratigraphic interval. However, biogenic gas may have been generated in the coals.

Assessment Unit Model

The Pennsylvanian Saginaw Coal Bed Gas AU is restricted to beds of coal within the Saginaw Formation. Numerous coal beds are present within the Saginaw Formation, but the extent of these coal beds is limited, and most of the thicker and more extensive coal beds have been mined. The assessment unit might contain a continuous petroleum accumulation. It is possible that the coal beds may have generated some natural gas, although even this possibility appears to be very limited on account of the limited thickness and limited extent of the various coal beds. If present, undiscovered petroleum resources in the Pennsylvanian Saginaw Coal Bed Gas AU would probably consist of biogenic gas. Furthermore, the generation of any gas in the coals is likely to have occurred during the Quaternary, following a scenario that is similar to the one proposed by Martini and others (1996) for biogenic gas generation for the Antrim Shale. Migration of the gas away from the coal beds is not likely to have occurred, and the coal beds themselves would be considered to be reservoir traps and seals. Siliciclastic mudstone (shale) overlying the coal beds could also act as a reservoir seal.

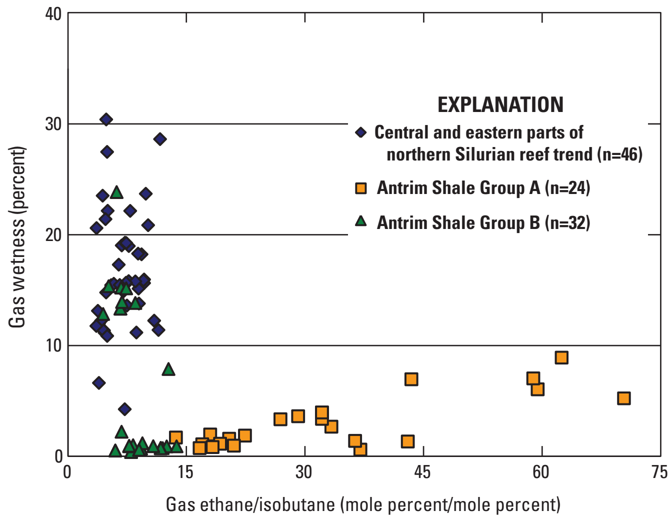


Figure 119. Plot of ethane/isobutane (mole percent/mole percent) versus gas wetness (percent) for two sets of natural gas samples (Antrim Shale Group A and Antrim Shale Group B) collected from wells producing from the Upper Devonian Antrim Shale and a set of natural gas samples from wells producing from the Middle Silurian Niagara Group in the central and eastern parts of the northern Silurian reef trend. Gas wetness percent = $100 \times (1- [C_1 \text{ mole percent}/\Sigma C_1–C_5 \text{ mole percent}])$; n=number of gas samples.

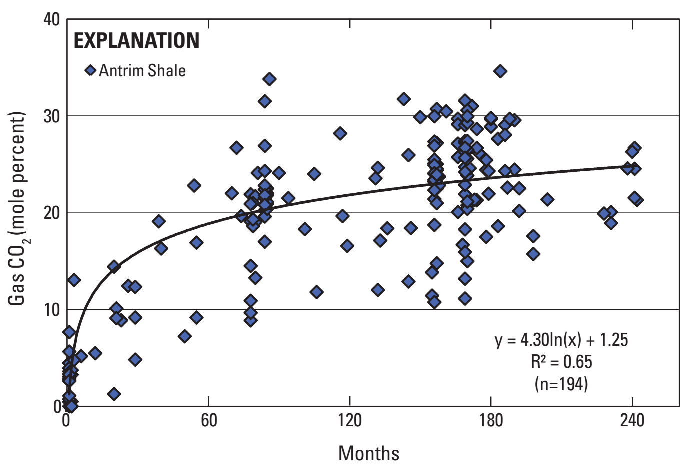


Figure 120. Plot of time (months) between well completion date and sample collection date and carbon dioxide (CO_2) content (mole percent) for 197 natural gas samples collected from wells producing from the Upper Devonian Antrim Shale in northern Michigan. y = gas CO_2 content (mole percent); x = months; R^2 = correlation coefficient at 95 percent confidence level; n = number of gas samples.

Reservoir Characteristics

As of the 2004 assessment, petroleum had not been produced commercially from the Pennsylvanian Saginaw Coal Bed Gas AU. Numerous coal beds are present within the Saginaw Formation, and rank of these coal beds range from high-volatile-C to high-volatile-B bituminous coal (Cohee and others, 1950; Catacosinos and others, 2001). The extent of these coal beds, however, is limited. Coal mining in Michigan reached a production peak in 1907 and was essentially terminated by 1950 (fig. 125).

According to Cohee and others (1950) and Catacosinos and others (2001), most of the areas of “proved” coal contain less than 150 acres, very few of the coal beds have thicknesses greater than 3 ft, and most of the coal beds thicken, thin, and (or) pinch out entirely over distances of a few hundred feet. In fact, only three coal beds have any lateral persistence: (1) Saginaw coal bed, (2) Lower Verne coal bed, and (3) Upper Verne coal bed (fig. 121). Furthermore, laboratory analyses by Smith (1912) show that the Upper Verne coal bed is the only gassy coal in Michigan. This coal bed, which was mined only in Bay County, is generally 2.5 ft thick, but in some places (that are now mined out) the coal bed reached a thickness of 3 to 4 ft. The coal has medium amounts of sulfur and rank is high-volatile-C bituminous coal. Both Lane (1902) and Smith (1912) noted that practically all of the coal beds in Michigan lie below the water table, and that fire damp, coal dust explosions, and noxious gases are practically nonexistent.

Undiscovered Petroleum Resources

For the 2004 assessment of undiscovered, technically recoverable oil and gas resources of the U.S. portion of the Michigan Basin, the USGS identified the Pennsylvanian Saginaw Coal Bed Gas AU but did not quantitatively assess it (Swezey and others, 2005). At the time of the assessment, no petroleum production had been established from this assessment unit, and not enough information was available to conduct a quantitative assessment. Based on the descriptions given above, the USGS estimated the potential for undiscovered coalbed gas within the Pennsylvanian Saginaw Coal Bed Gas AU to be negligible.

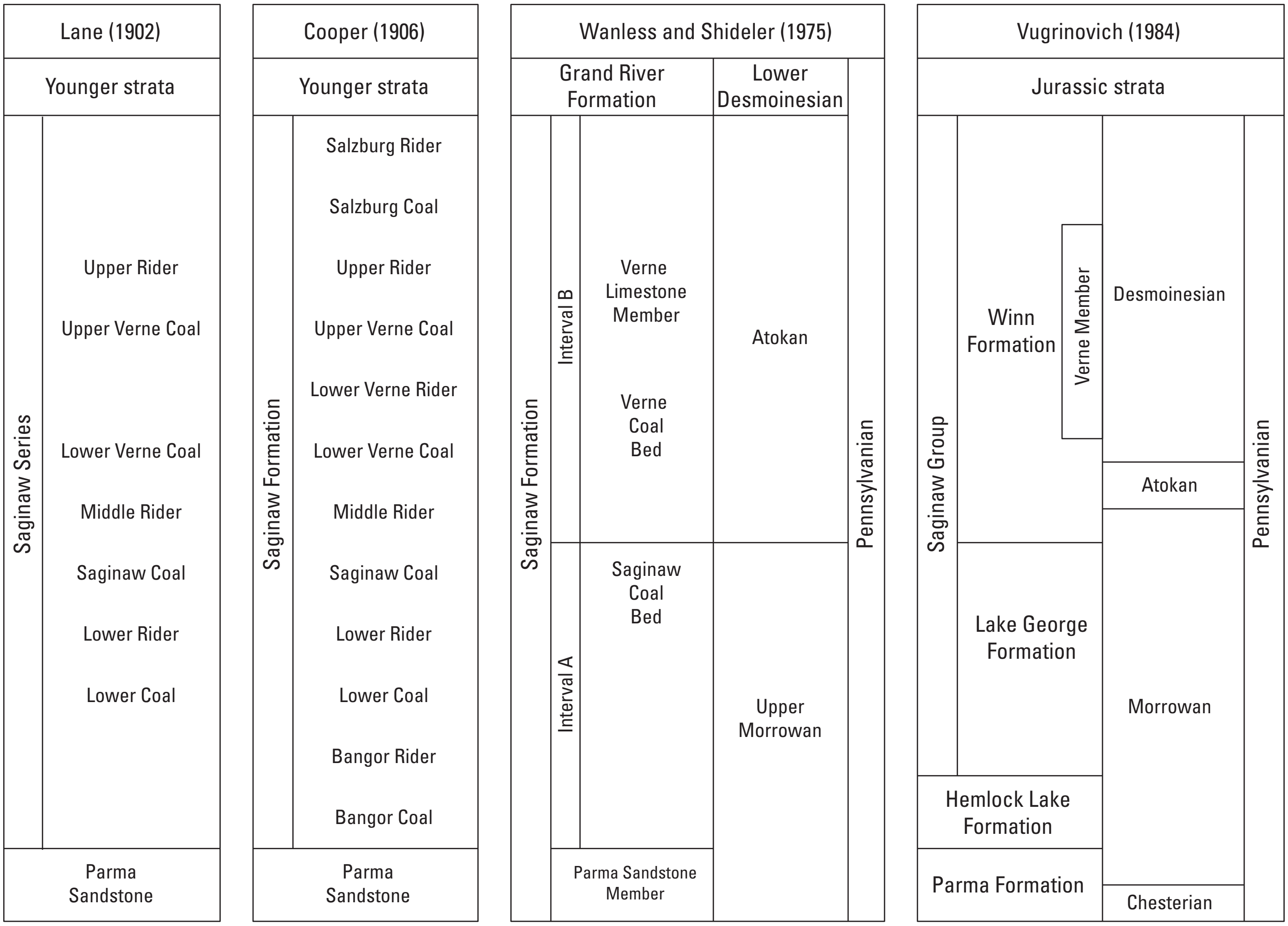


Figure 121. Chart showing Pennsylvanian stratigraphic nomenclature as used by earlier workers in Michigan (modified from Ells, 1979c; Vugrinovich, 1984).

The base map for this figure is from Nicholson and others (2004).

Figure 122. Map of isopachs of the lower part of the Pennsylvanian Saginaw Formation in the central part of the Michigan Basin (from Wanless and Shideler, 1975).

The base map for this figure is from Nicholson and others (2004).

Figure 123. Map of isopachs of the upper part of the Pennsylvanian Saginaw Formation in the central part of the Michigan Basin (from Wanless and Shideler, 1975).

The base map for this figure is from Nicholson and others (2004).

Figure 124. Structure map on base of the Pennsylvanian Saginaw Formation in the central part of the Michigan Basin (modified from Vugrinovich, 1984).

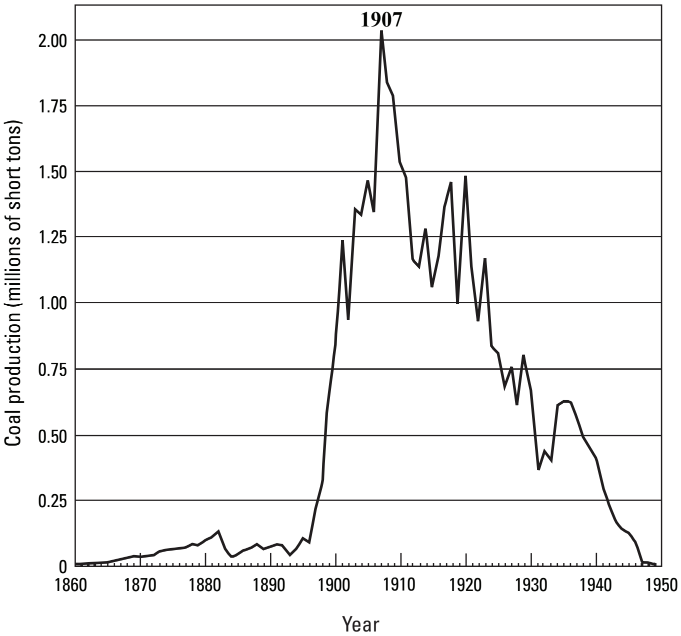


Figure 125. Graph of coal production (millions of short tons) in Michigan from 1860 to 1949 (after Cohee and others, 1950).

Summary

In 2004, the U.S. Geological Survey completed an assessment of the undiscovered oil and gas potential of the U.S. portion of the Michigan Basin. This assessment was based on the identification and characterization of the geologic elements of the total petroleum systems (TPS) in the basin. The geologic elements include the petroleum source rocks (source-rock potential, source-rock maturation, and petroleum generation and migration), reservoir rocks (sequence stratigraphy and petrophysical properties), and petroleum traps (trap formation and timing). Using this geologic framework, the USGS defined six total petroleum systems: (1) Precambrian Nonesuch TPS; (2) Ordovician Foster TPS; (3) Ordovician to Devonian Composite TPS; (4) Silurian Niagara/Salina TPS; (5) Devonian Antrim TPS; and (6) Pennsylvanian Saginaw TPS.

Thirteen assessment units (AUs) were identified within the six total petroleum systems; nine are characterized as conventional oil and gas accumulations and four are characterized as continuous accumulations. The nine conventional assessment units are (1) Precambrian Nonesuch AU, (2) Ordovician Sandstones and Carbonates AU, (3) Ordovician Trenton/Black River AU, (4) Silurian Burnt Bluff AU, (5) Silurian Niagara AU, (6) Silurian A-1 Carbonate AU, (7) Devonian Sylvania Sandstone AU, (8) Middle Devonian Carbonates AU, which includes the Detroit River Group, Dundee Limestone, and Traverse Group, and (9) Devonian to Mississippian Berea/Michigan Sandstones AU. All but the Precambrian Nonesuch AU, were quantitatively assessed. The four continuous assessment units are (1) Ordovician Collingwood Shale Gas AU, (2) Devonian Antrim Continuous Oil AU, (3) Devonian Antrim Continuous Gas AU, and (4) Pennsylvanian Saginaw Coal Bed Gas AU. Of these four continuous assessment units, only the Devonian Antrim Continuous Gas AU was quantitatively assessed. The means and the ranges of uncertainty (F95, F50, and F5 fractiles) for quantities of undiscovered, technically recoverable oil and gas resources in the Michigan Basin, are listed and summarized in table 17 (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume).

Figure 126 is a summary chart that illustrates the mean, F95, and F5 volumes (from table 17) of undiscovered, technically recoverable oil resources for the four units that were assessed. Similarly, figure 127 illustrates the mean, F95, and F5 volumes of undiscovered, technically recoverable gas resources for the 10 units that were assessed (both gas fields and associated gas in oil fields). The F50 volumes (medians) are not included on figures 126 and 127 as they are generally not distinguishable from the means at the scale of the figures.

Of the four units assessed for oil resources (fig. 126), the Ordovician Trenton/Black River AU has the highest potential for undiscovered, technically recoverable oil, with an estimated mean of 723 MMBO. The Silurian Niagara AU has the second highest potential with an estimated mean of 211 MMBO. Of the 10 units assessed for gas resources (fig. 127), the Devonian Antrim Continuous Gas AU has the highest potential for undiscovered, technically recoverable gas, with an estimated mean of 7.48 TCFG. Other assessment units with significant potentials for gas (both gas and oil fields) include the Ordovician Trenton/Black River AU (mean = 2.00 TCFG), the Silurian Niagara AU (mean = 1.08 TCFG), and the Ordovician Sandstones and Carbonates AU (mean value = 559 BCFG). The data listed in table 17 show that the Ordovician Trenton/Black River AU has the highest potential for undiscovered, technically recoverable natural-gas liquids (both gas and oil fields), with an estimated mean of 112 MMBNGL. The Silurian Niagara AU has the second highest potential with an estimated mean value of 74.9 MMBNGL).

Total estimated quantities of undiscovered, technically recoverable oil and gas resources present in the U.S. portion of the Michigan Basin are as follows:

1. Oil resources mean = 990 MMBO; F95 to F5 = 287 to 88 BBO;

2. Gas resources mean = 14 TCFG; F95 to F5 = 64 to 16 TCFG; and

3. Natural gas liquids resources mean = 219 MMBNGL; F95 to F5 = 66 to 453 MMBNGL.

Table 17. Michigan Basin oil and gas assessment results.

[All tabulated results are for technically recoverable resources; MMBO, million barrels of oil; BCFG, billion cubic feet of gas; MMBNGL, million barrels of natural gas liquids. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 represents a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Results are for the U.S. portion of the basin only; TPS, total petroleum system; AU, assessment unit. Gray shade indicates not applicable or not assessed quantitatively (Swezey and others, 2005, their table 1; table 1 of chap. 1, this volume)]

	Total petroleum systems and assessment units	Field type	Total undiscovered resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Conventional oil and gas resources	Silurian Niagara/Salina TPS													
	Devonian Sylvania Sandstone AU	Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Gas					0.00	10.69	23.90	10.31	0.00	0.00	1.63	0.66
	Silurian Niagara AU	Oil	95.61	207.73	335.95	211.22	179.41	414.73	759.36	434.69	12.75	31.43	63.46	33.91
		Gas					286.98	622.92	1,038.49	640.45	16.68	38.87	72.49	40.99
	Ordovician to Devonian Composite TPS													
	Devonian to Mississippian Berea/Michigan Sandstones AU	Oil	1.98	5.03	9.84	5.27	0.90	2.40	5.25	2.63	0.03	0.09	0.22	0.11
		Gas					11.36	31.84	66.94	34.58	0.42	1.24	2.85	1.38
	Middle Devonian Carbonates AU	Oil	10.77	43.35	108.35	50.53	5.07	21.95	56.92	25.27	0.38	1.70	4.74	2.02
		Gas					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Silurian A-1 Carbonate AU	Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Gas					26.26	94.56	213.73	104.25	0.49	1.84	4.52	2.08
	Silurian Burnt Bluff AU	Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Gas					43.81	138.86	285.77	149.42	0.82	2.70	6.08	2.99
	Ordovician Trenton/Black River AU	Oil	178.56	671.09	1,426.96	722.98	333.30	1,301.49	3,039.52	1,445.06	21.95	88.51	223.93	101.20
		Gas					122.36	502.39	1,171.51	556.96	2.30	9.72	24.81	11.15
	Ordovician Foster TPS													
	Ordovician Sandstones and Carbonates AU	Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Gas					148.66	524.06	1,073.90	558.90	5.74	21.37	48.15	23.45
	Precambrian Nonesuch TPS													
	Precambrian Nonesuch AU	Oil	Not assessed quantitatively											
	Total conventional resources		286.92	929.20	1,881.10	990.00	1,158.11	3,665.89	7,735.29	3,962.52	61.56	198.13	452.88	219.94
Continuous oil and gas resources	Pennsylvanian Saginaw TPS													
	Pennsylvanian Saginaw Coal Bed Gas AU	Gas	Not assessed quantitatively											
	Devonian Antrim TPS													
	Devonian Antrim Continuous Gas AU	Gas					5,483.97	7,356.74	9,869.05	7,475.02	0.00	0.00	0.00	0.00
	Ordovician to Devonian Composite TPS													
	Devonian Antrim Continuous Oil AU	Oil	Not assessed quantitatively											
	Ordovician Collingwood Shale Gas AU	Oil	Not assessed quantitatively											
	Total continuous resources						5,483.97	7,356.74	9,869.05	7,475.02	0.00	0.00	0.00	0.00
	Total undiscovered oil and gas resources		286.92	929.20	1,881.10	990.00	6,642.08	11,022.63	17,604.34	11,437.54	61.56	198.13	452.88	219.94

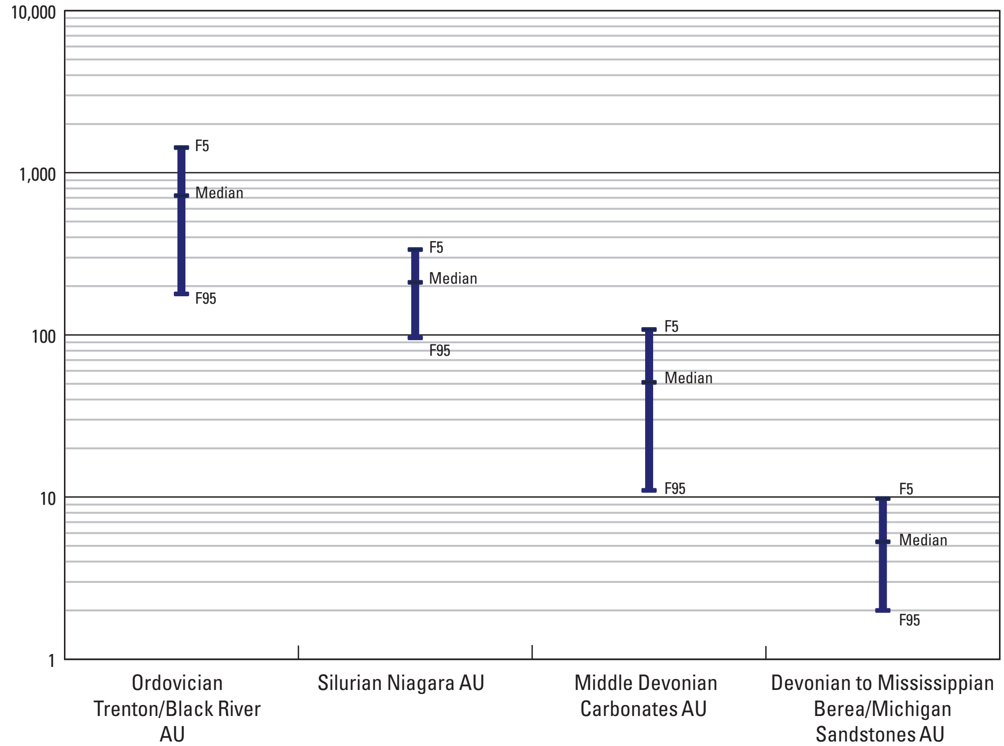


Figure 126. Summary chart illustrating the medians (F50), F95, and F5 volumes of undiscovered, technically recoverable oil resources for (1) Ordovician Trenton/Black River Assessment Unit (AU), (2) Silurian Niagara AU, (3) Middle Devonian Carbonates AU, and (4) Devonian to Mississippian Berea/Michigan Sandstones AU in the U.S. portion of the Michigan Basin. Data are from Swezey and others (2005, their table 1). Resources are in million barrels of oil; F95 represents a 95-percent chance of at least the amount tabulated; F5 represents a 5-percent chance.

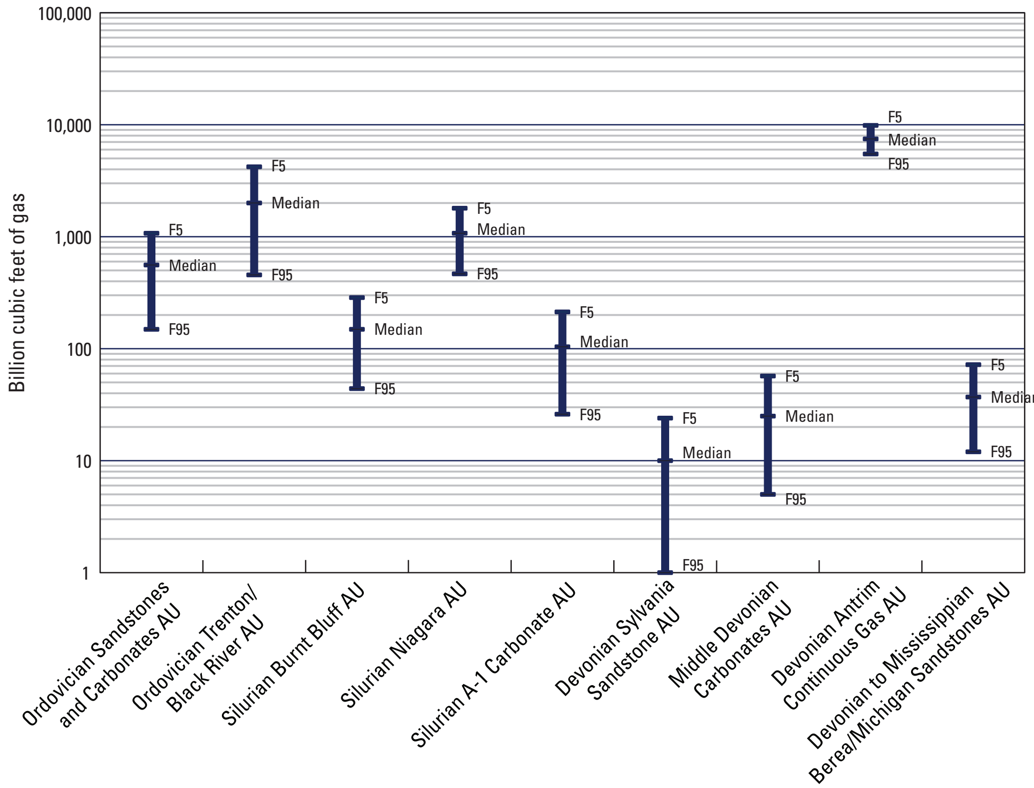


Figure 127. Summary chart illustrating medians (F50), F95, and F5 volumes of undiscovered, technically recoverable gas resources for (1) Ordovician Sandstones and Carbonates Assessment Unit (AU), (2) Ordovician Trenton/Black River AU, (3) Silurian Burnt Bluff AU, (4) Silurian Niagara AU, (5) Silurian A-1 Carbonate AU, (6) Devonian Sylvania Sandstone AU, (7) Middle Devonian Carbonates AU, (8) Devonian Antrim Continuous Gas AU, and (9) Devonian to Mississippian Berea/Michigan Sandstones AU in the U.S. portion of the Michigan Basin. Data are from Swezey and others (2005, their table 1). Resources are in billion cubic feet of gas; F95 represents a 95-percent chance of at least the amount tabulated; F5 represents a 5-percent chance.

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